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Overfire Air Technology for Tangentially Fired Utility Boilers Burning Western U.S. Coal

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OVERFIRE AIR TECHNOLOGY FOR TANGENTIALLY FIRED UTILITY BOILERS BURNING WESTERN U.S. COAL

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16. ABSTRACT The report gives results of an investigation and evaluation of the effectiveness of overfire air in reducing NOx emissions from tangentially fired boilers burning Western U.S. coal. Results are compared with those obtained during phase II, 'Program for Reduction of NOx from Tangentially Coal Fired Boilers,' EPA contract 68-02-1367. Both programs investigated the effect that variations in excess air, unit slagging, load, and overfire air had on unit performance and emissions. The effect of biasing combustion air through various out-of-service fuel nozzle elevations was also investigated. The effect of overfire air operation on waterwall corrosion potential was evaluated during 30-day baseline and overfire air corrosion coupon tests. Overfire air operation for low NOx optimization did not significantly increase corrosion coupon degradation. Overfire air operation and reductions in excess air levels were effective in reducing NOx emissions. NOx reductions of 20-30% were obtained when operating with 15-20% overfire air. These reductions occurred with the boilers operating at a total unit excess air of about 15-25%, measured at the economizer outlet. Unit loading exhibited a minimal effect on NOx emissions. Waterwall slag conditions had wide and inconsistent effects on NOx emission levels.

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Combustion Control	NOx Reduction	21B
Coal	Tangential Firing	21D
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FIELD TEST PROGRAM TO STUDY STAGED COMBUSTION TECHNOLOGY FOR TANGENTIALLY FIRED UTILITY BOILERS BURNING WESTERN U.S. COAL TYPES

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ABSTRACT

This report presents the findings of a program designed to investigate and evaluate the effectiveness of employing overfire air as a method of reducing NO_x emission levels from tangentially fired boilers burning Western U.S. coal types. This work was performed under the sponsorship of the Office of Research and Development of the Environmental Protection Agency (Contract 68-02-1486). The results of this program are compared with the results obtained under Phase II "Program for Reduction of NO_x from Tangentially Coal Fired Boilers" (Contract 68-02-1367).

These test programs investigated the effect that variations in excess air, unit slagging, load and overfire air had on unit performance and emission levels. Additionally, the effect of biasing combustion air through various out-of-service fuel nozzle elevations was also investigated. The effect of overfire air operation on waterwall corrosion potential was evaluated during thirty (30) day baseline and overfire air corrosion coupon tests. The results of the corrosion coupon tests indicate that overfire air operation for low NO_x optimization will not result in significant increases in corrosion coupon degradation.

Overfire air operation and reductions in excess air levels were found to be effective in reducing NO_x emission levels. NO_x reductions of 20 to 30 percent were obtained when operating with 15 to 20 percent overfire air. These reductions occurred with the boilers operating at a total unit excess air of approximately 15 to 25 percent as measured at the economizer outlet. Unit loading exhibited a minimal effect on NO_x emission levels. Waterwall slag conditions were found to have wide and inconsistent effects on NO_x emission levels.

CONTENTS

	PAGE NO.
Disclaimer	ii
Abstract	iii
List of Figures	vii
List of Data Sheets	xi
Conversion Table	xiii
List of Abbreviations and Symbols	xiv
Acknowledgment	xv
Section I	
Introduction	1
Conclusions	
Normal Operation	3
Biased Firing Operation	3
Overfire Air Operation	3
Recommendations	5
Summary	
Baseline Operation Study	6
Biased Firing Operation Study	11
Overfire Air Operation Study	11
Boiler Performance	22
Waterwall Corrosion Coupon Evaluation	22
Section II - EPA Contract 68-02-1486	
Objectives	
Task I - Unit Selection	26
Task II - Test Planning & Fabrication of Test Equipment	26
Task III - Installation of Instrumentation	27
Task IV - Baseline Operation	27
Task V - Biased Firing Operation	28
Task VI - Overfire Air Operation	30
Task VII - Preparation of Test Report and Analysis of Data	32
Discussion	
Task I - Unit Selection	33
Task II - Test Planning & Fabrication of Test Equipment	37
Task III - Installation of Instrumentation	37
Columbia Energy Center, Unit #1	
Tasks IV, V & VI - Test Data Acquisition and Analysis	41
Task IV - Baseline Operation Study	45
Load and Excess Air Variation - Clean Furnace	45
Load and Excess Air Variation - Moderately Dirty Furnace	46
Load and Excess Air Variation - Dirty Furnace	47
Analysis of Results	47
Task V - Biased Firing Study	48
Fuel Elevations Out of Service Variation	48

CONTENTS (Cont.)

PAGE NO.

Analysis of Results 53
Task VI - Overfire Air Operation Study 56
Excess Air and Overfire Air Rate Variation 56
Overfire Air Register Tilt Variation 58
Load and Furnace Waterwall Deposit Variation at Optimum Conditions 59
Analysis of Results 60
Furnace Performance 65
Waterwall Corrosion Coupon Evaluation 71

Huntington Station, Unit #2
Tasks IV, V & VI - Test Data Acquisition and Analysis 79
Task IV - Baseline Operation Study 83
Load and Excess Air Variation - Clean Furnace 83
Load and Excess Air Variation - Moderately Dirty Furnace . . 83
Load and Excess Air Variation - Dirty Furnace 84
Analysis of Results 85
Task V - Biased Firing Operation Study 89
Fuel Elevations Out-of-Service Variation 89
Analysis of Results 91
Task VI - Overfire Air Operation Study 95
Excess Air and Overfire Air Rate Variation 95
Overfire Air Tilt Variation 98
Load and Furnace Waterwall Deposit Variation at Optimum Conditions 99
Analysis of Results 100
Waterwall Corrosion Coupon Evaluation 105

Section III - EPA Contract 68-02-1367
Alabama Power Company, Barry Station, Unit #2
Introduction 115
Conclusions
Normal Operation 117
Overfire Air Operation 117
Objectives
Task I 119
Task II 119
Task III 119
Task IV 120
Task V 120
Task VI 120
Task VII 120
Task VIII 120
Task IX 120
Discussion
Task IV & V - Baseline and Biased Firing Test Programs 122
Test Data Acquisition and Analysis 122
Task IV - Baseline Test Study 124
Load and Excess Air Variation 124

CONTENTS (Cont.)

PAGE NO.

Furnace Wall Deposit Variation 131
Task V - Biased Firing Study 131
Fuel Elevations Out-of-Service Variation 131
Task VIII - Unit Optimization Study 135
Load and Excess Air Variation 135
Furnace Wall Deposit Variation 139
OFA Location, Rate, and Velocity Variation 144
OFA Tilt Variation 148
Load Variation at Optimum Conditions 153
Furnace Performance 157
Waterwall Corrosion Coupon Evaluation 157

Section IV - Application Guidelines
Introduction 170
Conclusions 171
Recommendations
Existing Steam Generating Units 172
New Steam Generating Units 172
Discussion
Design and Description of OFA Systems 174
Field Test Program 174
Exploratory Field Test Program - Existing Units 175
Effect on Unit Performance 176
Economic Evaluation 177
Applicability
Existing Steam Generating Units 181
New Steam Generating Units 181

References 182
Appendices
Appendix A - Wisconsin Power & Light Company
Test Data & Results 183
Appendix B - Utah Power & Light Company
Test Data & Results 242
Appendix C - Alabama Power Company
Test Data & Results 289
Appendix D - Compflow
Program Description 301

FIGURES

FIGURE		PAGE NO.
	(Section I)	
1	NO_2 vs. Theoretical Air, Baseline Study, Maximum Load . .	8
2	NO_2 vs. Theoretical Air, Baseline Study, 1/2 Load	9
3	NO_2 vs. Main Steam Flow, Baseline Study	10
4	CO vs. Theoretical Air, Baseline Study, Maximum Load . .	12
5	Carbon Heat Loss vs. Theoretical Air, Baseline Study Maximum Load	13
6	Fuel Elevation Out-of-Service vs. NO_2, Biased Firing Study	14
7	NO_2 vs. Theoretical Air, Biased Firing Study, Maximum Study	15
8	NO_2 vs. OFA Damper Opening, Overfire Air Study	17
9	NO_2 vs. Theoretical Air, Overfire Air Study, Test Series 1	18
10	NO_2 vs. Tilt Differential, Overfire Air Study	19
11	NO_2 vs. Theoretical Air, Overfire Air Study, Test Series 2	20
12	NO_2 vs. Theoretical Air, Overfire Air Study, Test Series 3	21
13	Unit Efficiency vs. Excess Air, Maximum Load	23
14	Corrosion Probe Assembly Drawing	24
	(Section II)	
15	Typical Windbox of Tangential Firing System	34
16	Unit Side Elevation - Columbia Energy Center, No. 1	35
17	Unit Side Elevation - Huntington Station, No. 2	36
	Section II: Columbia Energy Center, Unit #1	
18	Furnace Waterwall Deposit Pattern, Clean Furnace	43
19	Furnace Waterwall Deposit Pattern, Moderate Slag Furnace	44
20	Furnace Waterwall Deposit Pattern, Heavy Slag Furnace	45

FIGURES (Cont.)

FIGURE		PAGE NO.
21	NO_2 vs. Theoretical Air, Baseline Study	48
22	CO^2vs. Theoretical Air, Baseline Study	49
23	Carbon Heat Loss vs. Theoretical Air, Baseline Study . .	50
24	Unit Efficiency vs. Excess Air, Baseline Study	52
25	NO_2 vs. Theoretical Air, Biased Firing Study	54
26	Fuel Elevation Out-of-Service vs. NO_2, Biased Firing Study	55
27	Unit Efficiency vs. Excess Air, Biased Firing Study . . .	57
28	NO_2 vs. Theoretical Air, Overfire Air Study	61
29	CO^2vs. Theoretical Air, Overfire Air Study	62
30	Carbon Heat Loss vs. Theoretical Air, Overfire Air Study	63
31	NO_2 vs. Difference in Tilt, Overfire Air Study	64
32	Unit Efficiency vs. Excess Air, Overfire Air Study . . .	66
33	Chordal Thermocouple Locations	67
34	Elevation vs. Furnace Heat Absorption - Baseline Study	68
35	Elevation vs. Furnace Heat Absorption - Biased Firing Study	69
36	Elevation vs. Furnace Heat Absorption - Overfire Air Study	70
37	Waterwall Corrosion Probe Locations, Columbia #1	72
38	Typical Corrosion Probe Temperature Range	73
39	Gross MW Loading vs. Time - Baseline Corrosion Probe Study	74
40	Gross MW Loading vs. Time - Overfire Air Corrosion Probe Study	75
41	As-Fired Ash and Coupon Deposit Analysis, Baseline Study	77
42	As-Fired Ash and Coupon Deposit Analysis, Overfire Air Study	78
	Section II: Huntington Station, Unit #2	
43	Furnace Waterwall Deposit Pattern - Clean Furnace	80
44	Furnace Waterwall Deposit Pattern - Moderate Slag Furnace	81
45	Furnace Waterwall Deposit Pattern - Heavy Slag Furnace	82
46	NO_2 vs. Theoretical Air, Baseline Study	86

FIGURES (Cont.)

FIGURE		PAGE NO.
47	CO vs. Theoretical Air, Baseline Study	87
48	Carbon Heat Loss vs. Theoretical Air, Baseline Study	88
49	Unit Efficiency vs. Excess Air, Baseline Study	90
50	NO_2 vs. Theoretical Air, Biased Firing Study	92
51	Fuel Elevation Out-of-Service vs. NO_2, Biased Firing Study	93
52	CO vs. Theoretical Air, Biased Firing Study	94
53	Carbon Heat Loss vs. Theoretical Air, Biased Firing Study	96
54	Unit Efficiency vs. Excess Air, Biased Firing Study	97
55	NO_2 vs. Theoretical Air, Overfire Air Study	101
56	CO vs. Theoretical Air, Overfire Air Study	102
57	Carbon Heat Loss vs. Theoretical Air, Overfire Air Study	103
58	NO_2 vs. Tilt Differential, Overfire Air Study	104
59	Unit Efficiency vs. Excess Air, Overfire Air Study	106
60	Waterwall Corrosion Probe Locations, Huntington Station, No. 2	107
61	Typical Corrosion Probe Temperature Ranges, Huntington Station, No. 2	108
62	Gross MW Loading vs. Time - Baseline Corrosion Probe Study	109
63	Gross MW Loading vs. Time - Overfire Air Corrosion Probe Study	110
64	As-Fired Ash and Coupon Deposit Analysis, Baseline Study	113
65	As-Fired Ash and Coupon Deposit Analysis, Overfire Air Study	114
	Section III: Barry Station, Unit #3	
66	Unit Side Elevation, Barry Station, No. 2	116
67	Schematic Overfire Air System, Barry Station, No. 2	121
68	Gaseous Emissions Test System	123
69	Waterwall Corrosion Probe Locations, Barry Station, No. 2	125
70	Typical Corrosion Probe Temperature Range, Barry Station, No. 2	126
71	NO_2 vs. Theoretical Air, Baseline Study	127
72	CO vs. Theoretical Air, Baseline Study	128
73	Percent Carbon Loss vs. Theoretical Air, Baseline Study	129
74	Unit Efficiency vs. Unit Excess Air	130
75	Furnace Slag Pattern - Clean Furnace	132
76	Furnace Slag Pattern - Moderate Slag Furnace	133

FIGURES (Cont.)

FIGURE		PAGE NO.
77	Furnace Slag Pattern - Heavy Slag Furnace	134
78	NO_2 vs. Theoretical Air, Biased Firing Study	136
79	CO vs. Theoretical Air, Biased Firing Study	137
80	Percent Carbon Loss vs. Theoretical Air, Biased Firing Study	138
81	NO_2 vs. Theoretical Air, Overfire Air Study	140
82	CO vs. Theoretical Air, Overfire Air Study	141
83	Percent Carbon Loss vs. Theoretical Air, Overfire Air Study	142
84	Unit Efficiency vs. Excess Air	143
85	Furnace Slag Pattern - Clean Furnace	145
86	Furnace Slag Pattern - Moderate Slag Furnace	146
87	Furnace Slag Pattern - Heavy Slag Furnace	147
88	NO_2 vs. Theoretical Air, Overfire Air Study	149
89	CO vs. Theoretical Air, Overfire Air Study	150
90	Percent Carbon Loss vs. Theoretical Air, Overfire Air Study	151
91	NO_2 vs. Tilt Differential, Overfire Air Study	152
92	Percent Carbon Loss vs. Tilt Differential, Overfire Air Study	154
93	CO vs. Tilt Differential, Overfire Air Study	155
94	NO_2 vs. Main Steam Flow	156
95	Chordal Thermocouple Locations on Furnace Waterwalls	158
96	Average Centerline Absorption Profile - Test 14	159
97	Average Centerline Absorption Profile - Test 24	160
98	Average Centerline Absorption Profile - Test 33	161
99	Average Centerline Absorption Profile - All Tests	162
100	Gross MW Loading vs. Time - Baseline Corrosion Probe Study	164
101	Gross MW Loading vs. Time - Biased Firing Corrosion Probe Study	165
102	Gross MW Loading vs. Time - Overfire Air Corrosion Probe Study	166
103	Ash Analysis	169
	Section IV: Application Guidelines	
104	Overfire Air System Costs	178

DATA SHEETS

SHEET		PAGE NO.
A1, A2	Baseline Operation Study - Emissions Test Data, Columbia #1	184, 185
A3, A4	Biased Firing Operation Study - Emissions Test Data, Columbia #1	186, 187
A5, A6	Overfire Air Operation Study - Emissions Test Data, Columbia #1	188, 189
A7, A8	Baseline Operation Study - Test Data, Columbia #1	190, 191
A9, A10	Biased Firing Operation Study - Test Data, Columbia #1	192, 193
A11 - A13	Overfire Air Operation Study - Test Data, Columbia #1	194 - 196
A14, A15	Baseline Operation Study - Test Results, Columbia #1	197, 198
A16, A17	Biased Firing Operation Study - Test Results, Columbia #1	199, 200
A18 - A21	Overfire Air Operation Study - Test Results, Columbia #1	201 - 204
A22 - A25	Baseline Operation Study - Waterwall Absorption Rates, KW/m^2, Columbia #1	205 - 208
A26 - A29	Biased Firing Operation Study - Waterwall Absorption Rates, KW/m^2, Columbia #1	209 - 212
A30 - A35	Overfire Air Operation Study - Waterwall Absorption Rates, KW/m^2, Columbia #1	213 - 218
A36 - A41	Baseline Operation Study - Board & Computer Data, Columbia #1	219 - 224
A42 - A47	Biased Firing Operation Study - Board & Computer Data, Columbia #1	225 - 230
A48 - A56	Overfire Air Operation Study - Board & Computer Data, Columbia #1	231 - 239
A57	Waterwall Corrosion Coupon Data Summary - Baseline Test, Columbia #1	240
A58	Waterwall Corrosion Coupon Data Summary - Overfire Air Test, Columbia #1	241
B1, B2	Baseline Operation Study - Emissions Test Data, Huntington #2	243, 244
B3, B4	Biased Firing Operation Study - Emissions Test Data, Huntington #2	245, 246
B5, B6	Overfire Air Operation Study - Emissions Test Data, Huntington #2	247, 248
B7, B8	Baseline Operation Study - Test Data, Huntington #2	249, 250
B9, B10	Biased Firing Operation Study - Test Data, Huntington #2	251, 252

DATA SHEETS (Cont.)

SHEET		PAGE NO.
B11 - B13	Overfire Air Operation Study - Test Data, Huntington #2	253 - 255
B14 - B17	Baseline Operation Study - Test Results, Huntington #2	256 - 259
B18, B19	Biased Firing Operation Study - Test Results, Huntington #2	260, 261
B20 - B23	Overfire Air Operation Study - Test Results, Huntington #2	262 - 265
B24 - B29	Baseline Operation Study - Board & Computer Data, Huntington #2	266 - 271
B30 - B35	Biased Firing Operation Study - Board & Computer Data, Huntington #2	272 - 277
B36 - B44	Overfire Air Operation Study - Board & Computer Data, Huntington #2	278 - 286
B45	Waterwall Corrosion Coupon Data Summary - Baseline Test, Huntington #2	287
B46	Waterwall Corrosion Coupon Data Summary - Overfire Air Test, Huntington #2	288
C1	NO_x Test Data Summary - Baseline Study Before Modification, Barry #2	290
C2	NO_x Test Data Summary - Biased Firing Study Barry #2	291
C3	NO_x Test Data Summary - Baseline Study After Modification, Barry #2	292
C4	NO_x Test Data Summary - OFA Location, Rate and Velocity Variation, Barry #2	293
C5	NO_x Test Data Summary - OFA Tilt and Load Variation, Barry #2	294
C6	Waterwall Absorption Rates, kg-cal/hr-cm^2 - Right Wall Centerline Tube Rates, Barry #2	295
C7	Waterwall Absorption Rates, kg-cal/hr-cm^2 - Front Wall Centerline Tube Rates, Barry #2	296
C8	Waterwall Absorption Rates, kg-cal/hr-cm^2 - Right Wall, Rear Wall, Left Wall, Front Wall, Barry #2	297
C9	Waterwall Corrosion Coupon Data Summary - Baseline Test, Barry #2	298
C10	Waterwall Corrosion Coupon Data Summary - Biased Firing Test, Barry #2	299
C11	Waterwall Corrosion Coupon Data Summary - Overfire Air Test, Barry #2	300

CONVERSION FACTORS

SI METRIC UNITS TO ENGLISH UNITS

To Convert From	To	Multiply By
kg/s	10^3LB/HR	7.936640
ng/J	LB/10^6BTU	2.326E-3
MJ/s	10^6BTU/HR	3.412141
ug/J	LB/10^6BTU	2.326
kJ/kg	BTU/LB	4.299226E-1
MPa	PSIA	1.450377E+2
KW/m^2	10^6BTU/HR-FT^2	3.16998E-1

ENGLISH UNITS TO SI METRIC UNITS

To Convert From	To	Multiply By
10^3LB/HR	kg/s	1.259979E-01
PSIA	MPa	6.894757E-3
LB/10^6BTU	ng/J	4.29922E+2
LB/10^6BTU	ug/J	4.29922E-1
10^6BTU/HR	MJ/s	2.930711E-1
BTU/LB	kJ/kg	2.326
10^6BTU/HR-FT^2	KW/m^2	3.154594

$^oF = 1.8(^oC)+32^o$

ABBREVIATIONS AND SYMBOLS

Abbreviations	Definitions
NO_x	Oxides of Nitrogen
THC	Total Hydrocarbons
NA	Not Available
X-S	Excess
WW	Waterwall
MCR	Maximum Continuous Rating
TA	Theoretical Air to Fuel Firing Zone
EA	Excess Air
FFZ	Fuel Firing Zone
NSPS	New Source Performance Standard

Symbols	
NO_2	Nitrogen Dioxide
CO	Carbon Monoxide
O_2	Oxygen
SO_2	Sulfur Dioxide
CO_2	Carbon Dioxide

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1. Alabama Power Company
   Barry Station, Unit #2

2. Utah Power and Light Company
   Huntington Station, Unit #2

3. Wisconsin Power and Light Company
   Columbia Station, Unit #1

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SECTION I

INTRODUCTION

The emphasis on improved quality of the environment has led to the design of coal fired steam generators with the capability of using overfire air to reduce and control NO_x emission levels. For tangentially fired steam generators, the overfire air is admitted through registers in an extended windbox.

Previous work with coal fired steam generators has demonstrated that overfire air simulation with tangential firing is effective in reducing NO_x emission levels by as much as 50 percent of uncontrolled values.

Some of this previous work was performed by Combustion Engineering, Inc. under an EPA-sponsored two-phase program to identify, develop and recommend the most promising combustion modification techniques for the reduction of NO_x emissions from tangentially coal fired utility boilers with a minimum impact on unit performance.

This two-phase program is briefly described as follows:

Phase I (performed under EPA Contract 68-02-0264) consisted of selecting a suitable utility boiler to be modified for experimental studies to evaluate NO_x emission control. Phase I also included the preparation of preliminary drawings, a detailed preliminary test program, a cost estimate and detailed schedule of the program phases and a preliminary application economic study indicating the cost range of a variety of combustion modification techniques applicable to existing and new boilers [1]*.

Phase II (performed under EPA Contract 68-02-1367) consisted of modifying and testing the utility boiler selected in Phase I to evaluate overfire air and biased firing as methods for NO_x control. This phase also included:

1. The completion of detailed fabrication and erection drawings,
2. Installation of analytical test equipment,
3. Updating of the preliminary test program,
4. A baseline operation study,
5. Analysis and reporting of test results and,

* Numbers in brackets refer to references at end of report.

6. The development of control technology application guidelines for existing and new tangentially coal fired utility boilers.

This program was conducted at the Barry Steam Station, Unit #2 of the Alabama Power Company [2].

The majority of this previous work has been conducted on units firing Eastern or Midwestern bituminous coals.

In recent years, the utilization of Western U.S. coals as an energy source has increased significantly. The incentives for their use are the low sulfur content conducive to low SO_x emission levels and the large available reserves that may be used in lieu of oil and natural gas which are in short supply.

Based on Phase II recommendations to investigate Western coal types which were becoming a predominate source of fuel for electric generating stations, this study, EPA Contract 68-02-1486, was contracted by Combustion Engineering, Inc.'s, Field Testing and Performance Results Department.

The objective of this program was to investigate the effectiveness of employing overfire air as a method of reducing NO_x emission levels from tangentially fired boilers burning Western U.S. coals. The effect of reducing NO_x emission levels was evaluated with respect to unit performance, unit efficiency, waterwall corrosion rates and related gaseous emission levels.

Specifically, the factors considered in realizing this objective were as follows:

1. The program was conducted on two units designed with overfire air registers, the first unit firing a Western U.S. subbituminous coal and the second unit firing a Western U.S. bituminous coal.

2. The test program evaluated baseline, biased firing and overfire air operation and consisted of approximately 60 steady state tests per unit and two months of waterwall corrosion rate studies per unit.

3. The effect of NO_x control methods on all gaseous constituents was evaluated during all tests. The following constituents were measured: NO_x, SO_x, CO, THC, O_2 and particulate samples for unburned combustible analysis.

4. The effects of NO_x control methods on steam generator performance were evaluated during all tests by obtaining necessary temperatures, pressures, flows, etc., with calibrated equipment.

5. Based on the results of this program, conclusions and recommendations were made pertaining to the acceptable application of staged firing with respect to NO_x emission levels, corrosion rates and unit operation for each type of coal tested.

6. The results of this program were compared with the results obtained under Contract 68-02-1367 for a unit equipped with an overfire air system not included in the original design.

CONCLUSIONS

NORMAL OPERATION

1. Under normal unit operation without overfire air, excess air variation was found to have the greatest single effect on NO_x emission levels, increasing NO_x with increasing excess air. An average increase of 6.4 ng/J for each one percent change in excess air (EA) was observed over a normal operating range of 15 to 25 percent EA for the three units.

2. Unit loading was found to have a limited effect on NO_x and CO emission levels and carbon heat loss.

3. Variations in furnace waterwall deposits had wide and inconsistent effects on NO_x and CO emission levels and carbon heat loss.

4. Under normal unit operation, the percent carbon loss in the fly ash and CO emission levels increased with decreasing excess air with the increases becoming greater below a level of approximately 20 to 25 percent excess air. CO levels in excess of 24 ng/J were considered unacceptable for the purposes of this program.

BIASED FIRING OPERATION

Biased firing was found to be most effective when the top fuel firing elevation was removed from service. This mode of operation simulates overfire air operation. However, while biased firing is a potentially effective method of NO_x control, it may necessitate a reduction in unit loading. Therefore, biased firing is not considered to be the most desirable method of NO_x control.

OVERFIRE AIR OPERATION

1. NO_x reductions of 20 to 30 percent were obtained with 15 to 20 percent overfire air when operating at a total unit excess air of approximately 15 to 25 percent as measured at the economizer outlet.

   This condition would provide an <u>average</u> fuel firing zone stoichiometry of 95 to 105 percent of theoretical air. Stoichiometries below this range did not result in large enough decreases in NO_x levels to justify their use.

2. When using overfire air as a means of decreasing the theoretical air to the fuel firing zone, the combustible loss and CO emission levels were less affected than when operating with low excess air since during overfire air operation, acceptable overall excess air levels are maintained. Reduction in operating excess air levels for NO_x control is often precluded because of the ash properties of the coal being fired. Further, as coal is an extremely complex fuel characterized by wide variations in properties, even

between different seams in the same mine area, excess air is the only means available to the operator to compensate for departures from the design coal. For the above reasons, the application of overfire air rather than low excess air firing is recommended on coal fired steam generators.

3. Furnace performance as indicated by waterwall slag accumulations, visual observations and absorption rates were not affected by overfire air operation.

4. At Alabama Power Company's Barry Station Unit #2 where the overfire air port could not be installed as a windbox extension, test results indicated that the centerline of the overfire air port should be kept within 3 meters of the centerline of the top fuel elevation. Distances greater than 3 meters did not result in significantly decreased NO_x levels. On new designs, and whenever possible on field modified units, it is preferable to introduce the overfire air through a vertical extension of the windbox rather than through isolated ports displaced above the windbox. The effectiveness of introducing overfire air through an extended windbox is demonstrated via the tests conducted on Wisconsin Power & Light, Columbia #1 and Utah Power & Light, Huntington Canyon #2. The overfire air compartments on an extended windbox tilt independently of the remainder of the windbox to permit adjustments in the "point" of overfire air introduction.

5. Optimum overfire air operation was obtained when the overfire air registers were tilted away from the fuel nozzles. NO_x control was nearly as effective when the overfire air registers were tilted with the fuel nozzles. NO_x emission levels increased when the overfire air registers and fuel nozzles were directed toward each other. At Alabama Power Company's Barry Station Unit #2, flame stability decreased when the overfire air registers and fuel nozzles were directed away from each other by more than 20 to 25 degrees. This phenomena was not observed at either Wisconsin Power and Light Company's Columbia Energy Center Unit #1 or at Utah Power and Light Company's Huntington Station Unit #2. With the overfire air tilts fixed in a horizontal position, acceptable unit operation was obtained, however, NO_x levels varied with fuel nozzle position.

6. The results of the thirty day baseline and overfire air corrosion coupon runs indicate that the overfire air operation for low NO_x optimization did not result in significant increases in corrosion coupon degradation. Additional long-term operation studies will be required to verify these observations.

7. The average NO_x levels experienced during the thirty day overfire air studies were as follows: Barry #2-172 ng/J, Huntington Canyon #2-231 ng/J and Columbia #1-294 ng/J. The emission levels for Columbia #1 reflect operating conditions beyond the control of the test program.

8. Variables normally used to control normal boiler operation should not be considered as NO_x controls with coal firing. These variables include unit load, nozzle tilt, pulverizer fineness, windbox dampers and total excess air.

9. Overall unit efficiency was not affected by overfire air operation.

RECOMMENDATIONS

This program was designed to investigate the effects of the following process variables and combustion modifications on NO_x emission levels in existing steam generating units:

Process Variables

Excess Air Level
Unit Load
Furnace Waterwall Deposits

Combustion Modifications

Biased Firing
Overfire Air Firing

The effects of furnace waterwall deposits could not be adequately documented. Several investigations have indicated that furnace waterwall deposits can effect NO_x emission levels. Therefore, this process variable should be investigated further.

The effect of fuel nitrogen on NO_x formation was not investigated per se in this program. However, as the effect of fuel nitrogen is becoming of increasing concern, its contribution to NO_x emission levels in coal fired boilers should be quantified.

Additionally, the results of the corrosion probe evaluations indicate that the coupon weight losses encountered during a thirty day evaluation are small and consideration should be given to studies of up to one year duration to verify short term test results. These studies should include evaluation of actual fireside waterwall tube wastage rates as well as corrosion probe wastage rates.

SUMMARY

Percent excess air, bulk flame temperature and residence time of the combustion gases all directly affect the formation of oxides of nitrogen (NO_x). The two oxides of nitrogen which are of significance are nitric oxide (NO) and nitrogen dioxide (NO_2). NO is the more predominant form and accounts for 90 to 95 percent of the total NO_x generated in a utility boiler. Once it enters the atmosphere NO is converted to NO_2, which is more hazardous to human health. Most references in this report to NO_2 are actually refering to total nitrogen oxides. This method of expressing NO_x as NO_2 is in agreement with EPA practice.

While it is not the subject of this report, it should be noted that NO_x generated by the combustion of coal can occur by two mechanisms. One mechanism is by the oxidation of atmospheric nitrogen (thermal NO_x) while the other mechanism involves the conversion of fuel bound nitrogen (fuel NO_x). The formation of thermal NO_x is known to be dependent on flame temperature, oxygen concentration in the combustion zone and residence time at temperature.

Several investigators have observed that the formation of fuel NO_x is responsible for a significant portion of the total NO_x emitted from the combustion process [3,4,5,6]. The reaction can take place at a much lower flame temperature and has also been shown to be dependent on the oxygen concentration in the combustion zone. The coals being fired at Alabama Power Company's Barry #2 and Utah Power and Light Company's Huntington Canyon #2 had nitrogen analysis ranging from 1.1 to 1.3 percent nitrogen by weight. Wisconsin Power and Light Company's Columbia #1 had an analysis ranging from 0.6 to 0.8 percent nitrogen by weight. Preliminary plots of NO_2 versus the coal nitrogen content did not show any correlation between NO_2 and coal nitrogen content. Any correlation would probably have been masked by the limited range of the nitrogen content of the coals being fired and by the variation in excess air levels.

BASELINE OPERATION STUDY

It has been well documented that the formation of NO_x is dependent upon excess air and the oxygen concentration in the combustion zone. The oxygen concentration in the combustion zone is directly related to excess air and also to the theoretical air to the fuel firing zone (TA). TA is a computational tool used by Combustion Engineering, Inc. which accounts for variations in position and leakage in all windbox compartment dampers.* This method allows for the accounting of leakage in the compartments above the top active fuel compartment and, therefore, is a better approximation of the actual air (i.e., oxygen) available for combustion in the fuel firing zone than total excess air (EA). Therefore, all parameters are plotted versus theoretical air to the fuel firing

* See Appendix D.

zone rather than the total excess air. For the baseline operation study the TA is essentially the same as the total air since no air was diverted through the overfire air registers.

Figure 1 is a plot of NO_2* versus TA for the full load baseline tests at Alabama Power Company's Barry Station Unit #2, Utah Power and Light Company's Huntington Canyon Station Unit #2 and Wisconsin Power and Light Company's Columbia Energy Center Unit #1. As shown by this figure, NO_2 is proportional to TA and, therefore, to oxygen concentration in the fuel firing zone and excess air.

Figure 2 is a plot of NO_2 versus TA for the half (1/2) load tests for all three units. As with the full load tests, the half (1/2) load tests also show increasing NO_2 emission levels with increasing TA. Comparison of the full and half (1/2) load tests show that at similar theoretical air levels, the NO_2 emission levels for the half (1/2) load tests are lower than or equal to the NO_2 levels for the full load tests. The effect of load is better shown in Figure 3, where emission levels are plotted versus theoretical air level for full, three quarter and one half load baseline tests. This plot shows that in some, but not all cases, NO_2 levels tend to increase with unit loading. It can be shown that occasionally the opposite trend was observed.

While NO_2 levels correlated well with TA, attempts to find what effect fuel nozzle tilt and furnace condition had on NO_x formation were not as successful. Changes in fuel nozzle tilt were found to produce wide and inconsistent variations in NO_2 emission levels.

Other investigators have found that increased slagging of the furnace walls tends to increase NO_x by increasing the furnace outlet temperature and, therefore, the bulk flame temperature [3,5]. Bulk flame temperature increases due to the reduced heat transfer from the hot combustion gases to the water-cooled furnace walls. The amount of reduction in heat transfer may depend greatly upon the type of slag on the furnace walls. The furnace conditions for the full and half (1/2) load tests are indicated on Figures 1 and 2. Furnace condition was found to have wide and inconsistent effects on NO_2 emission levels for the tests run on the subject boilers. The results obtained showed that for some tests an increase in furnace slag resulted in an increase in NO_2 emission levels while no effect was observed for other tests. Furnace condition was measured by visual observation of the furnace waterwalls. Since waterwall absorption is closely related to furnace condition, an attempt was made to correlate NO_2 emission levels with furnace waterwall absorption and therefore with furnace condition. This attempt produced no meaningful results. The lack of correlation between NO_2 emission levels and furnace condition might be partially attributed to the fact that the visual observation of furnace waterwall deposits is very subjective. Also, the contribution of fuel nitrogen may be dominant in the formation of NO_x.

* In this report, oxides of nitrogen (NO_x) are expressed as nitrogen dioxide (NO_2) to be consistent with the requirements of the New Source Performance Standards, Federal Register Vol. 35, No. 247, Part II, Dated December 31, 1971.

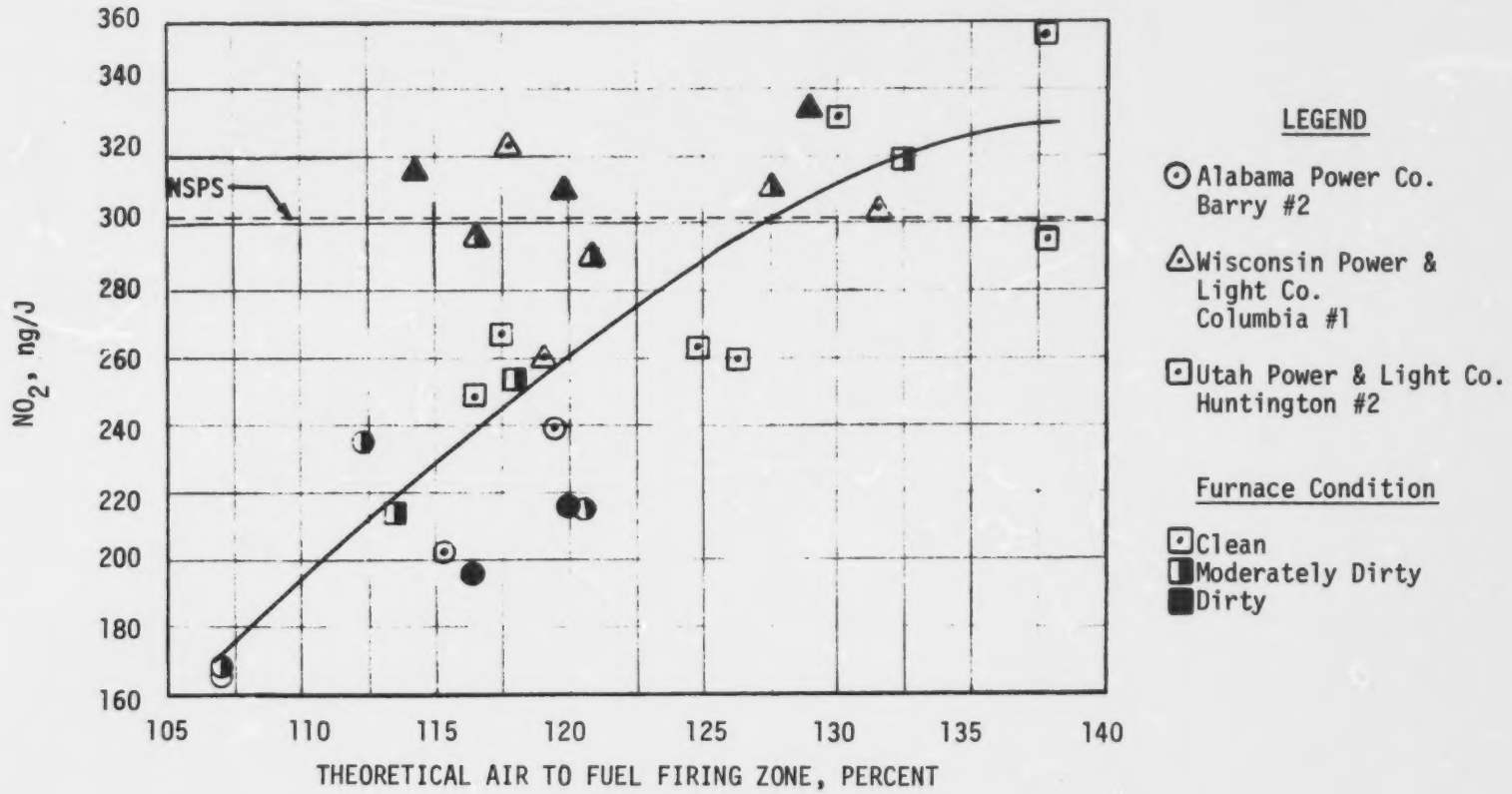
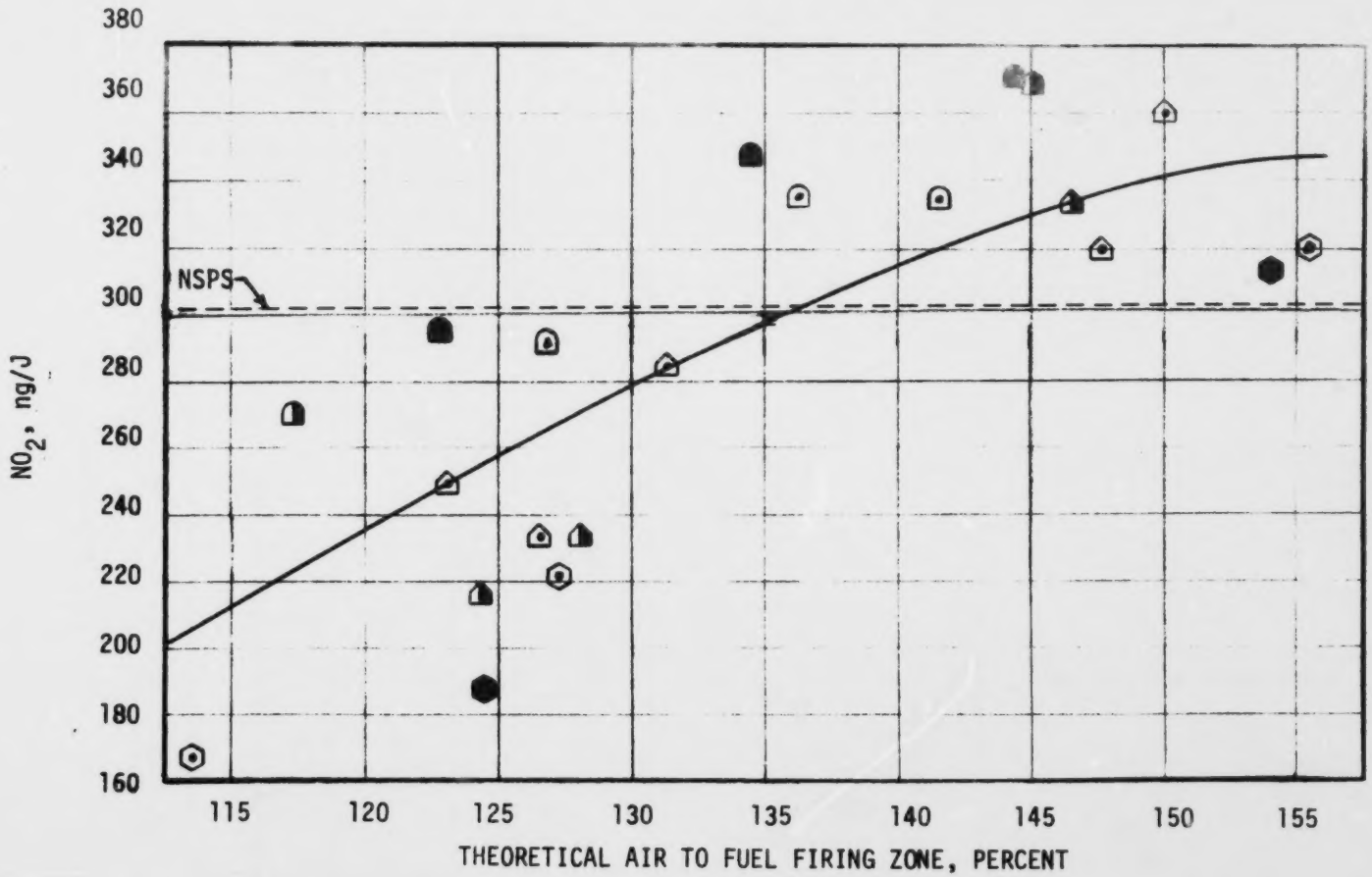


Figure 1: NO_2 vs. theoretical air, baseline study, maximum load



LEGEND

- Alabama Power Co., Barry #2
- Wisconsin Power & Light Co., Columbia #1
- Utah Power & Light Co., Huntington #2
- Clean
- Moderately Dirty
- Dirty

Figure 2: NO_2 vs. theoretical air, baseline study, 1/2 load

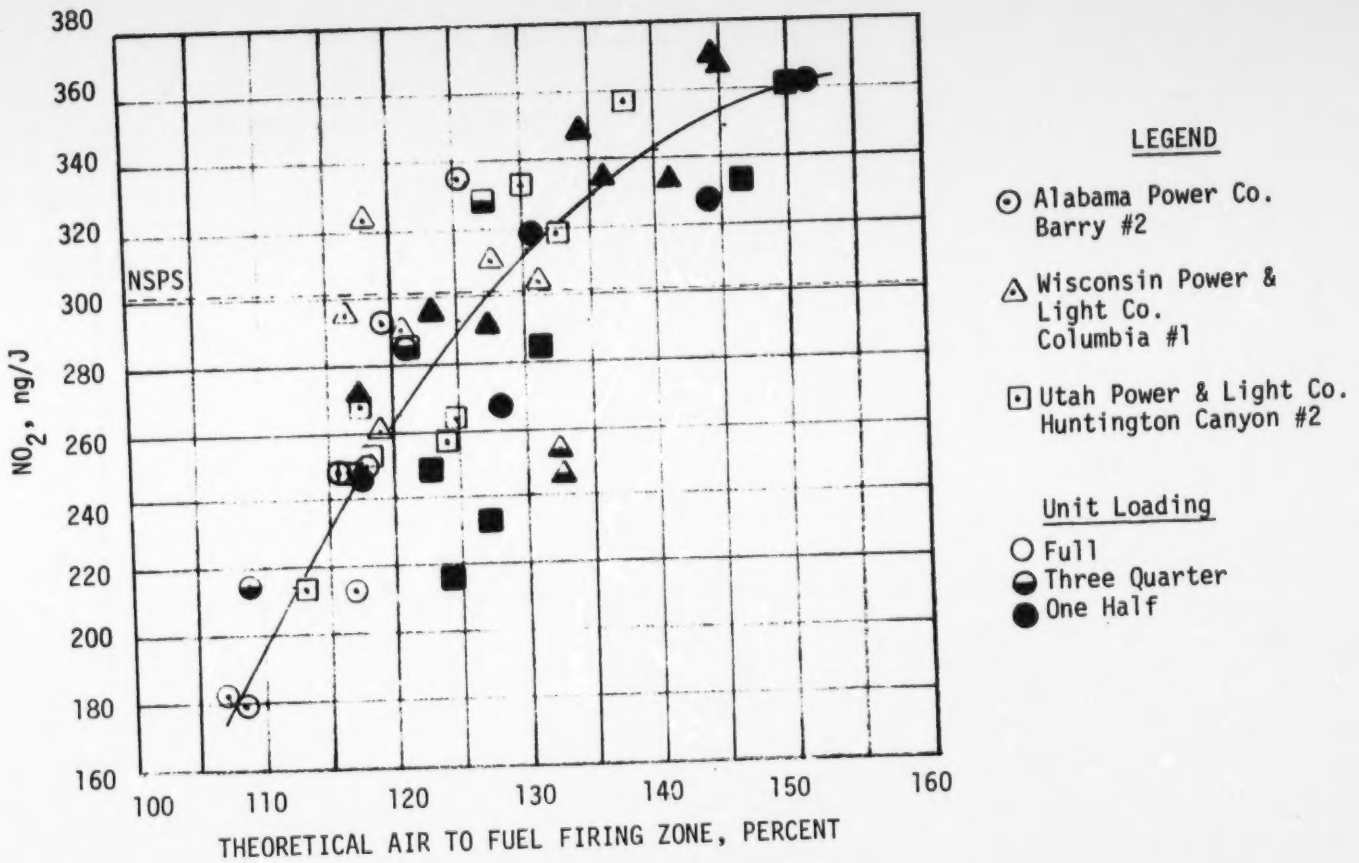


Figure 3: NO_2 vs. unit loading, baseline study

The effect of reducing TA on CO emission levels and carbon heat loss is shown on Figures 4 and 5 for the full load tests. Both CO emission levels and carbon heat loss increase with decreasing TA. This trend is a result of the reduced oxygen available for complete combustion. CO emission levels show no effect due to furnace condition. However, carbon heat loss appears to decrease with increasing furnace waterwall deposits. This may be related to the higher bulk flame temperatures encountered in a heavily slagged furnace.

BIASED FIRING OPERATION STUDY

Biased firing involves the removal of a full firing elevation from service with the dampers being opened so as to admit air through the idle fuel nozzle elevations. The effect on NO_2 emission levels when taking various fuel elevations out of service is shown in Figure 6. The lowest NO_2 levels for each unit were obtained when the top fuel firing elevations were removed from service and the respective compartment air dampers were 100 percent open. Overfire air operation is simulated by this method of unit operation. The trend is for increasing NO_2 levels as the elevation being removed is lower in the windbox. The increase in NO_2 levels can be attributed to the increased oxygen available in the fuel firing zone.

Examination of the units on an individual basis showed a slight reduction in NO_2 levels when the bottom fuel firing elevation was removed from service. This reduction in NO_2 might be caused by a cooling of the hot combustion gases by the cooler combustion air, which is being admitted through the bottom fuel firing elevation.

NO_2 is plotted versus TA for the full load biased firing tests in Figure 7. The correlation found for the baseline tests is also evident for the biased firing tests, NO_2 being directly proportional to TA.

CO emission level and carbon heat loss plots for the biased firing tests have not been included. Preliminary plots of these variables against TA revealed wide and inconsistent variations. This inconsistency is most probably due to firing with different fuel elevations out of service.

OVERFIRE AIR OPERATION STUDY

The overfire air operation studies were divided into three separate test series, each designed to determine an optimum operating condition. The three test series were:

1. Excess Air and Overfire Air Rate Variation,

2. Overfire Air Register Tilt Variation, and

3. Load and Furnace Waterwall Deposit Variation at Optimum Conditions

The first of these test series involved the variation of the overfire air rate at various excess air levels. Variation of the overfire air rate is accomplished by changing the overfire air register damper opening. The maximum overfire air rate corresponds to the overfire air register dampers being 100 percent open. With the exception of Alabama Power Co., Barry #2, the overfire air

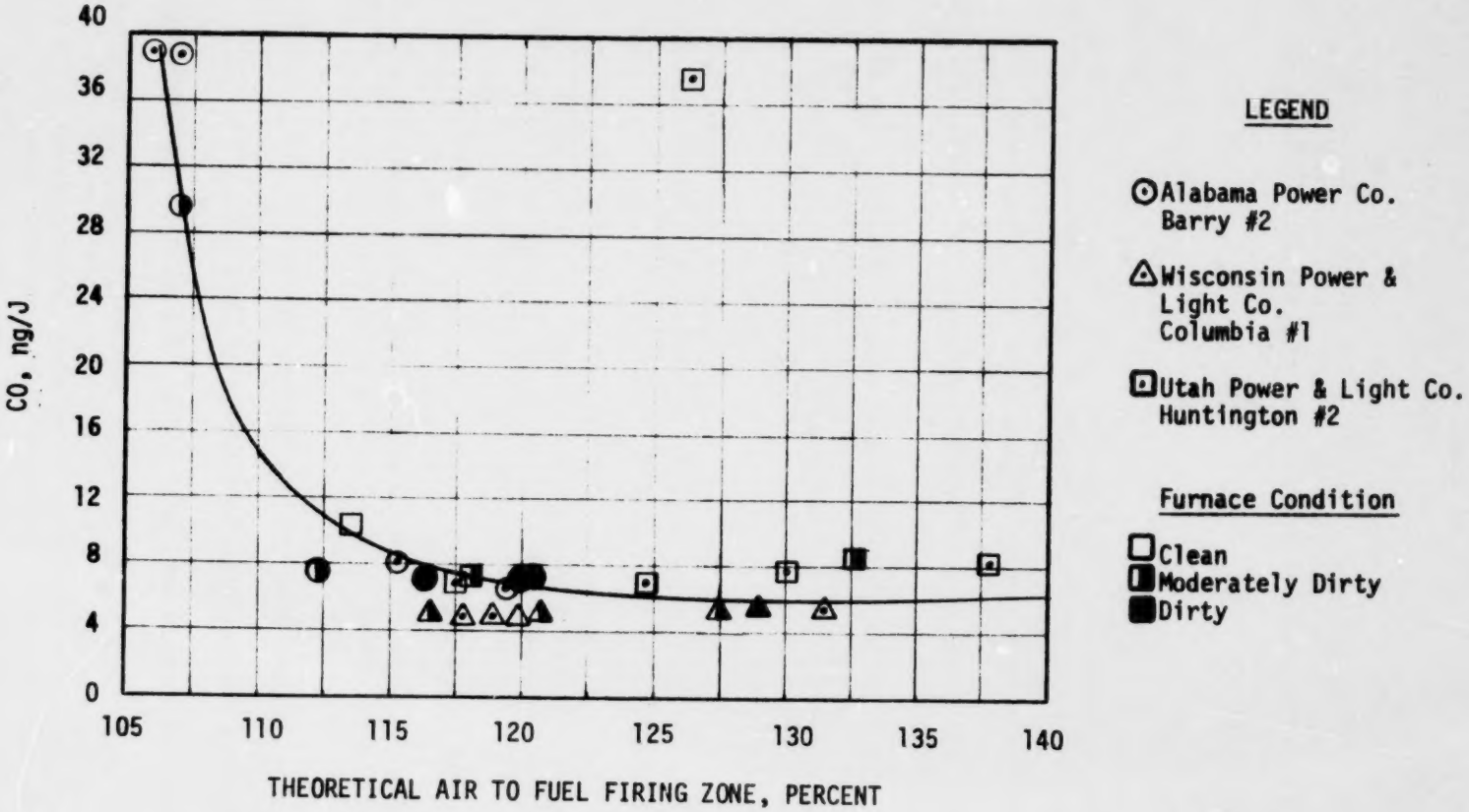


Figure 4: CO vs. theoretical air, baseline study, maximum load

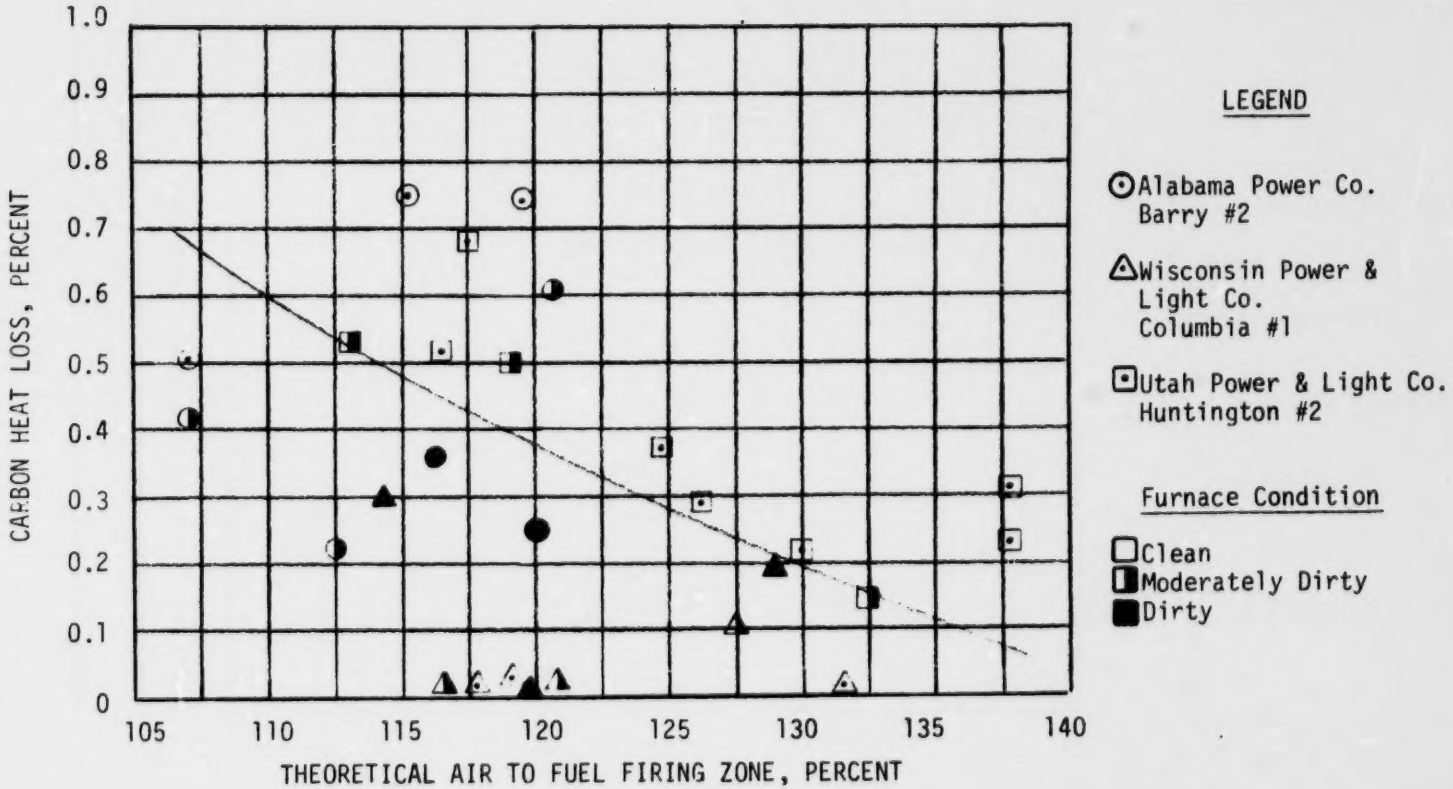


Figure 5: Carbon heat loss vs. theoretical air, baseline study, maximum load

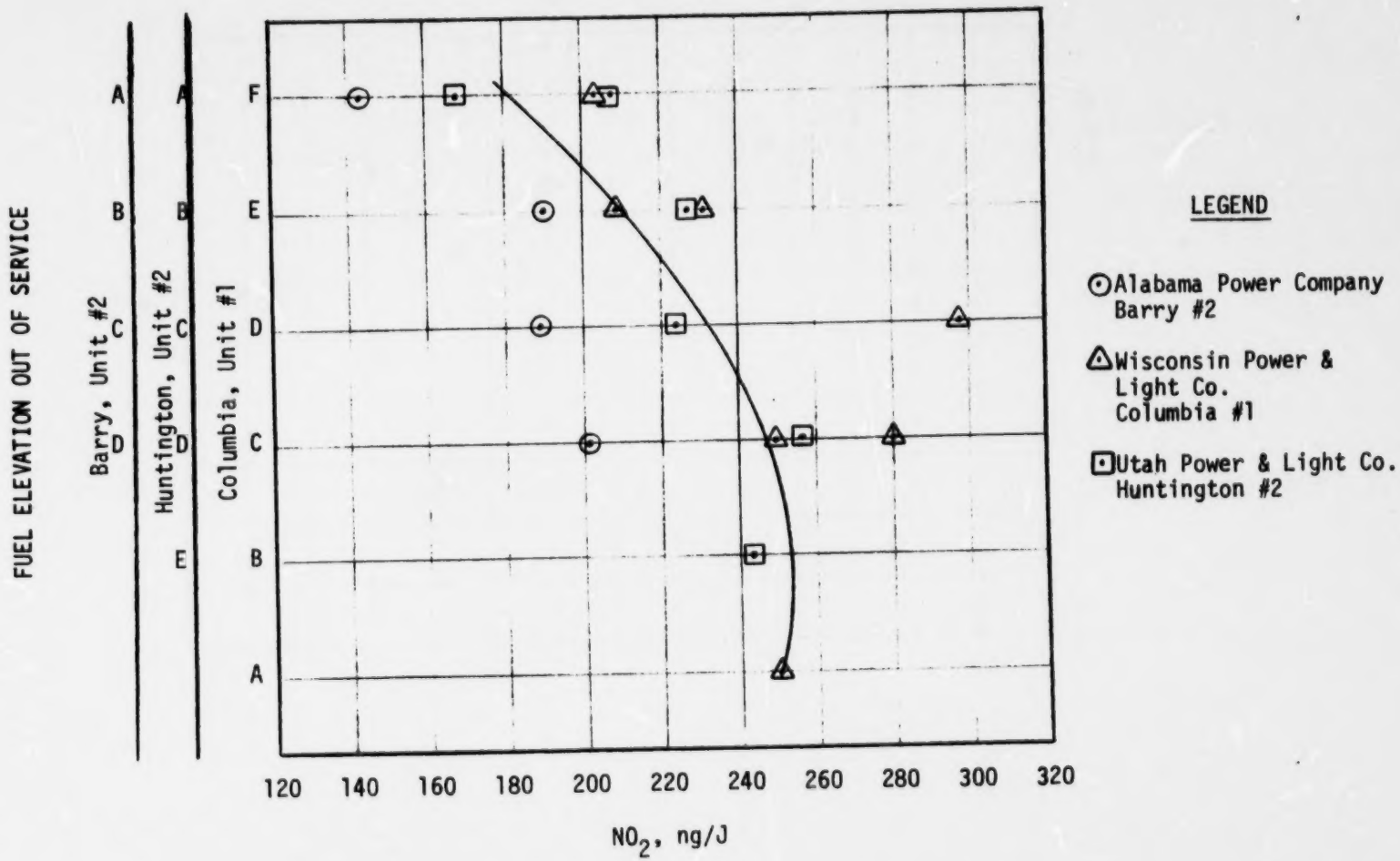


Figure 6: **Fuel elevation out of service vs. NO_2, biased firing study**

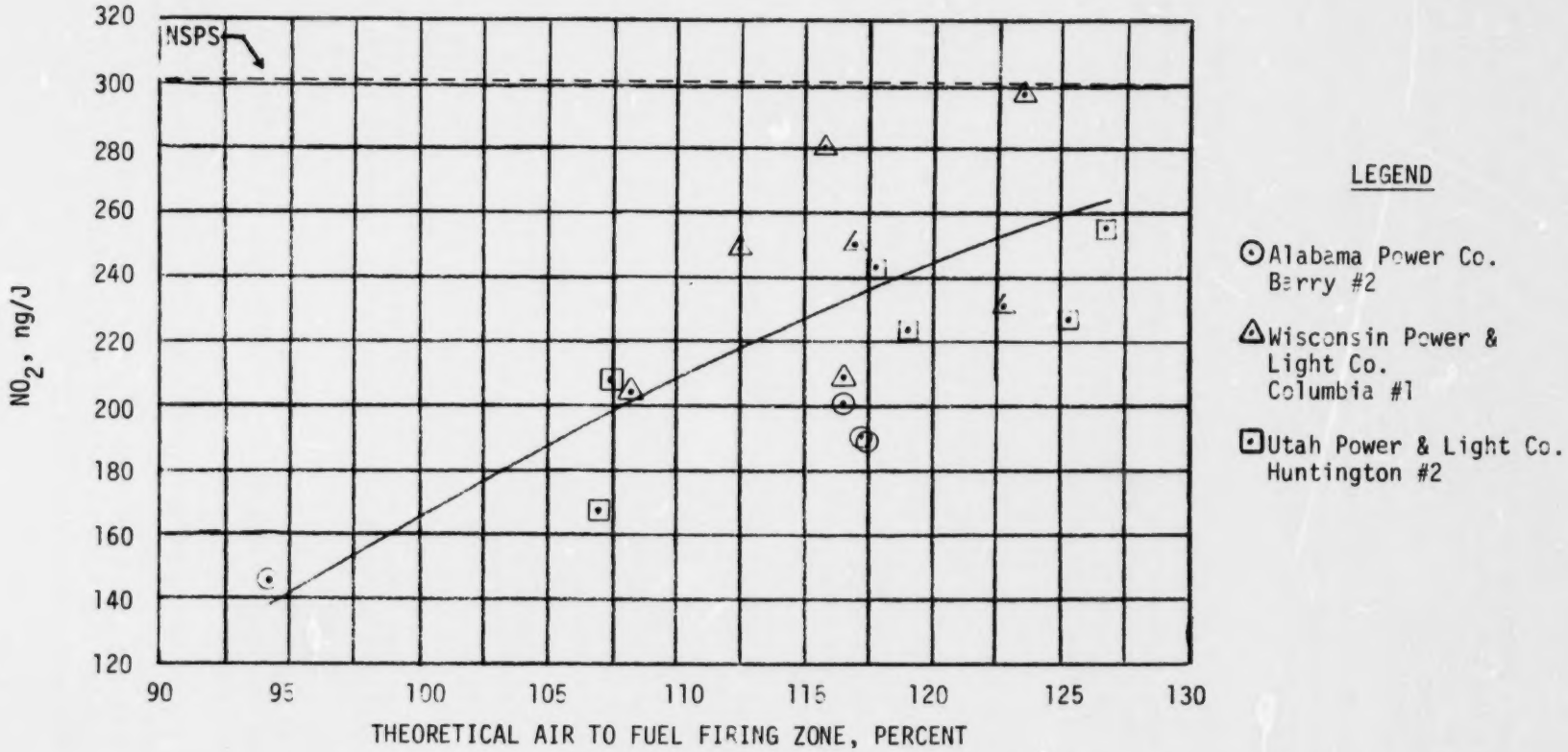


Figure 7: NO_2 vs. theoretical air, biased firing study, maximum load

systems were designed to introduce up to 15 percent of the total combustion air above the top level of fuel nozzles at MCR. Barry #2 was designed to introduce 20 percent of the total air as overfire air. During normal boiler operation the overfire air dampers are opened just enough to cool the overfire air registers.

As the overfire air dampers are opened the NO_2 emission levels are found to drop for a constant excess air level. This trend is shown in Figure 8. Six excess air levels have been shown, with the trend being similar for all excess air levels.

Theoretical air to the fuel firing zone and overfire air damper opening are closely related, with TA decreasing as the damper opening increases. Figure 9 is a plot of NO_2 versus TA for the damper variation tests for all three units. For these tests, as in the baseline and biased firing studies, the NO_2 emission levels are found to increase with increasing TA. The evidence shown in Figures 8 and 9 indicates that NO_x is more dependent upon TA rather than EA.

Once the optimum excess air level and overfire air rate had been determined for each unit, the second test series were run. This test series involved a variation in tilt of the overfire air registers and fuel nozzles. The variation in tilt refers to how many degrees toward or away from each other the fuel nozzles and overfire air registers are moved. This variation is calculated by taking the difference in degrees that the overfire air registers are angled toward or away from the fuel nozzles, i.e., overfire air register tilt minus fuel nozzle tilt.

Tilt variation of the fuel nozzles and overfire air registers is designed to move the fuel firing zone both in the furnace and in its position relative to the overfire air registers. Movement of the fuel nozzles and overfire air registers away from each other accentuates the effect of staged combustion. Movement of the fuel nozzles and overfire air registers toward each other minimizes the effect of staged combustion because the air is being forced down into the firing zone.

Figure 10 is a plot of NO_2 versus the difference in tilt of the fuel nozzles and overfire air registers. NO_2 emission levels are found to be highest when the overfire air registers and fuel nozzles are angled toward each other and lowest when they are angled away from each other. From the standpoint of NO_x reduction, the optimum tilt variation would be with the overfire air registers and fuel nozzles angled away from each other. However for ease of boiler operation, parallel operation of the overfire air registers and fuel nozzles would be best.

Figure 11 shows NO_2 plotted versus TA for the second series of tests in the overfire air study. Again, NO_2 emission levels are found to be directly proportional to TA.

In the final series of tests for each unit, the effects of load and furnace waterwall deposits on NO_x formation are examined. Boiler operation was at the optimum conditions determined in the previous test series for each unit. Half, three-quarter and full load tests were conducted on each unit at clean and dirty furnace conditions. Figure 12 is a plot of the NO_2 emission levels

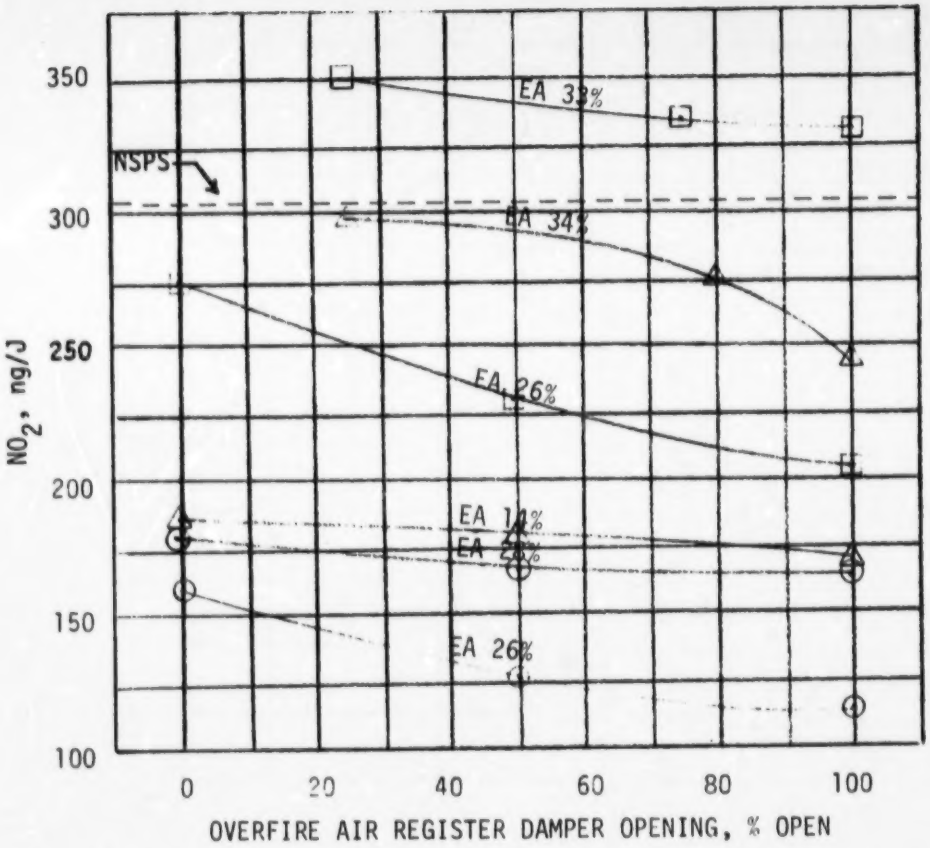


Figure 8: NO_2 vs. OFA damper opening, overfire study

LEGEND

⊙ Alabama Power Co.
Barry #2

△ Wisconsin Power & Light Co.
Columbia #1

⊡ Utah Power & Light Co.
Huntington #2

EA-Excess Air at Economizer Outlet

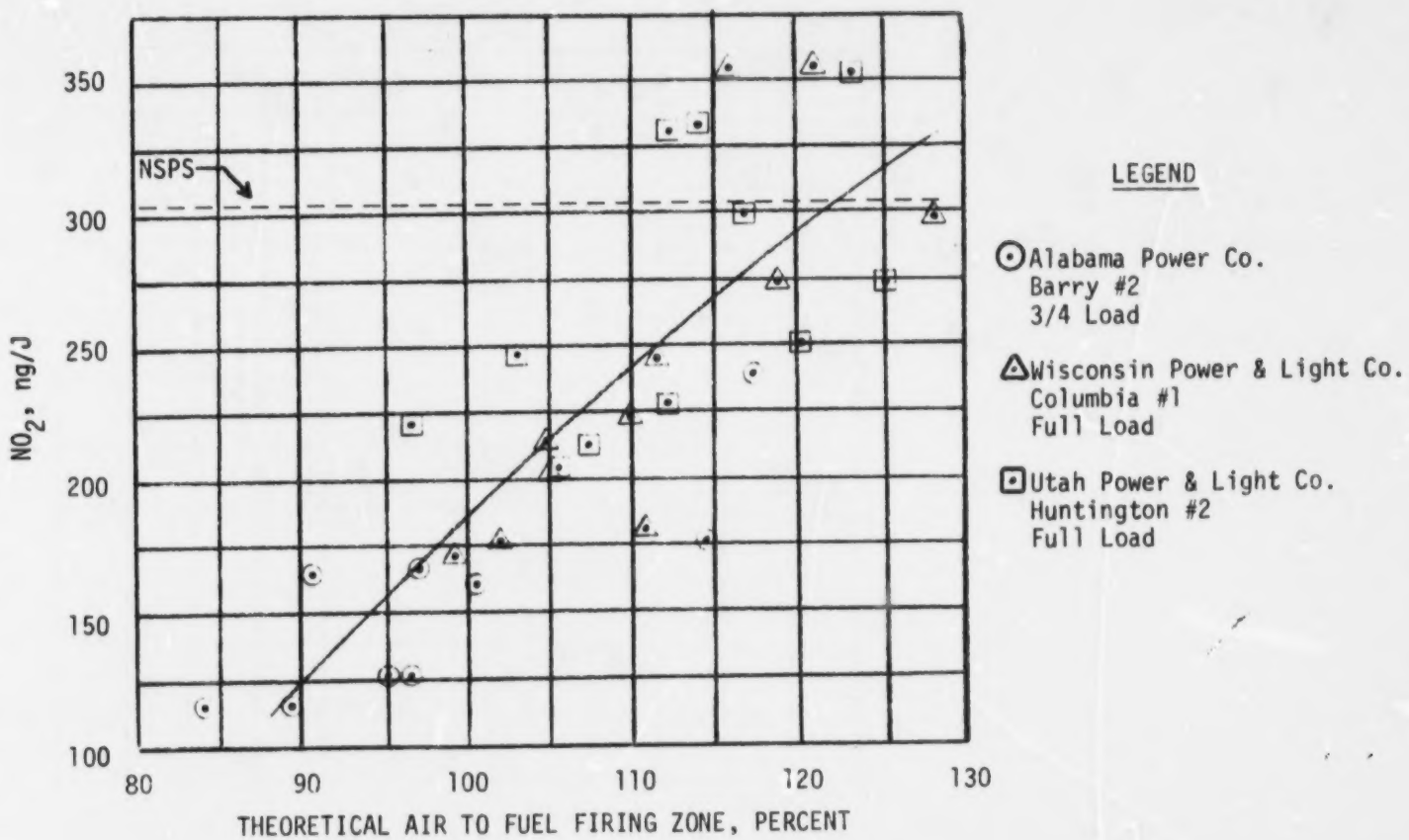


Figure 9: NO_2 vs. theoretical air, overfire air study, Test series 1

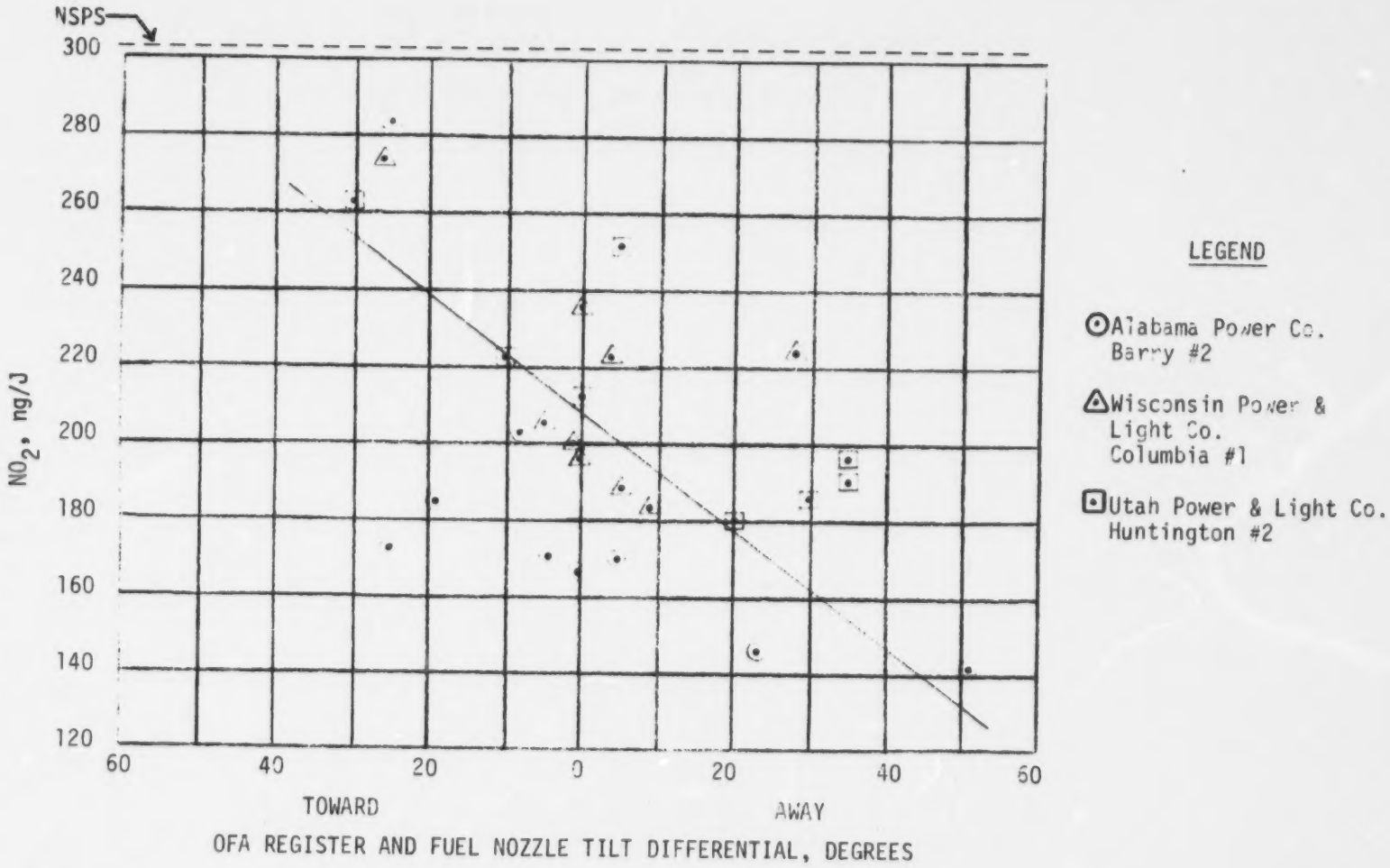


Figure 10: NO_2 Vs. tilt differential, overfire air study

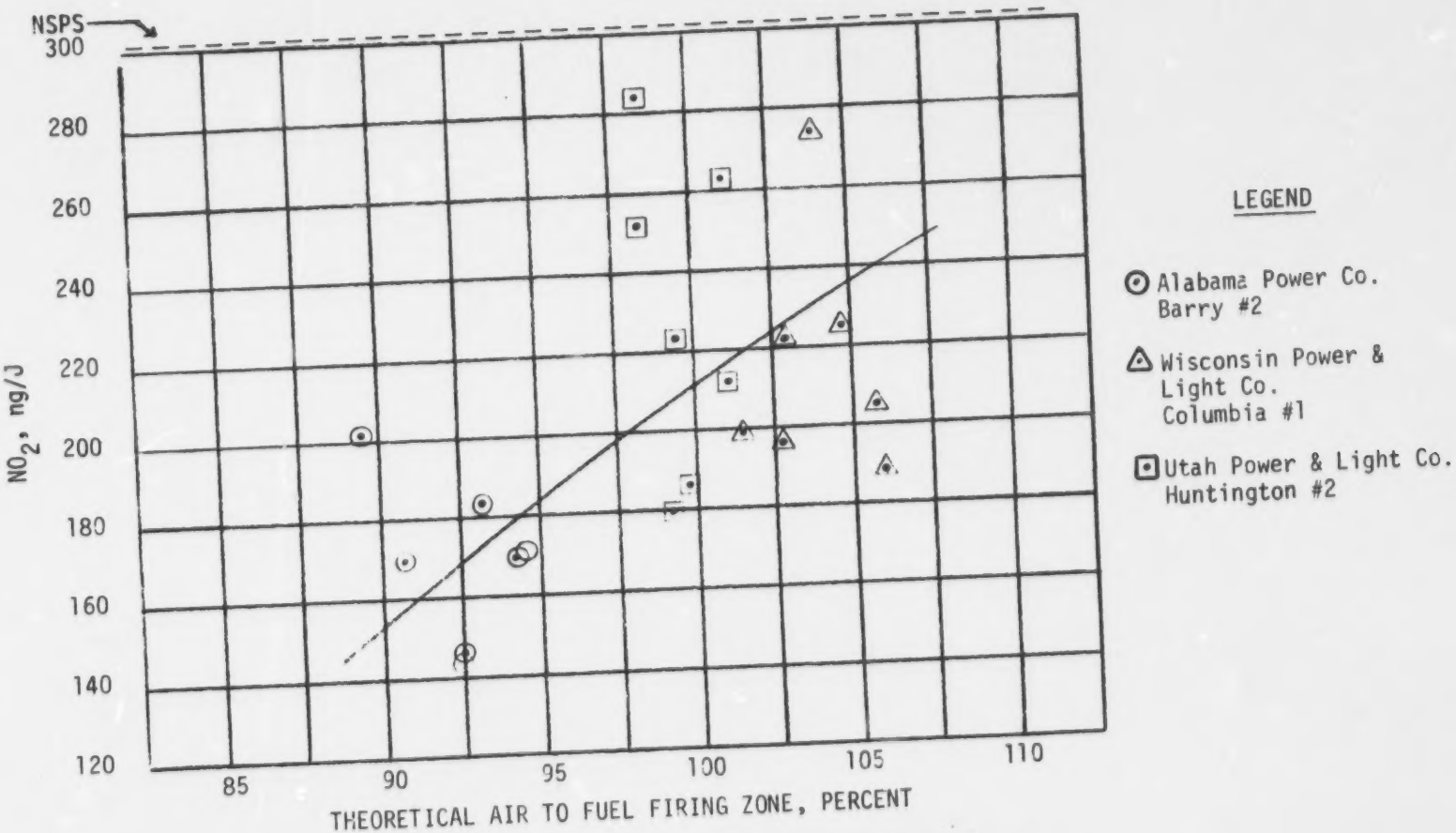


Figure 11: NO_2 vs. theoretical air, overfire air study, Test series 2

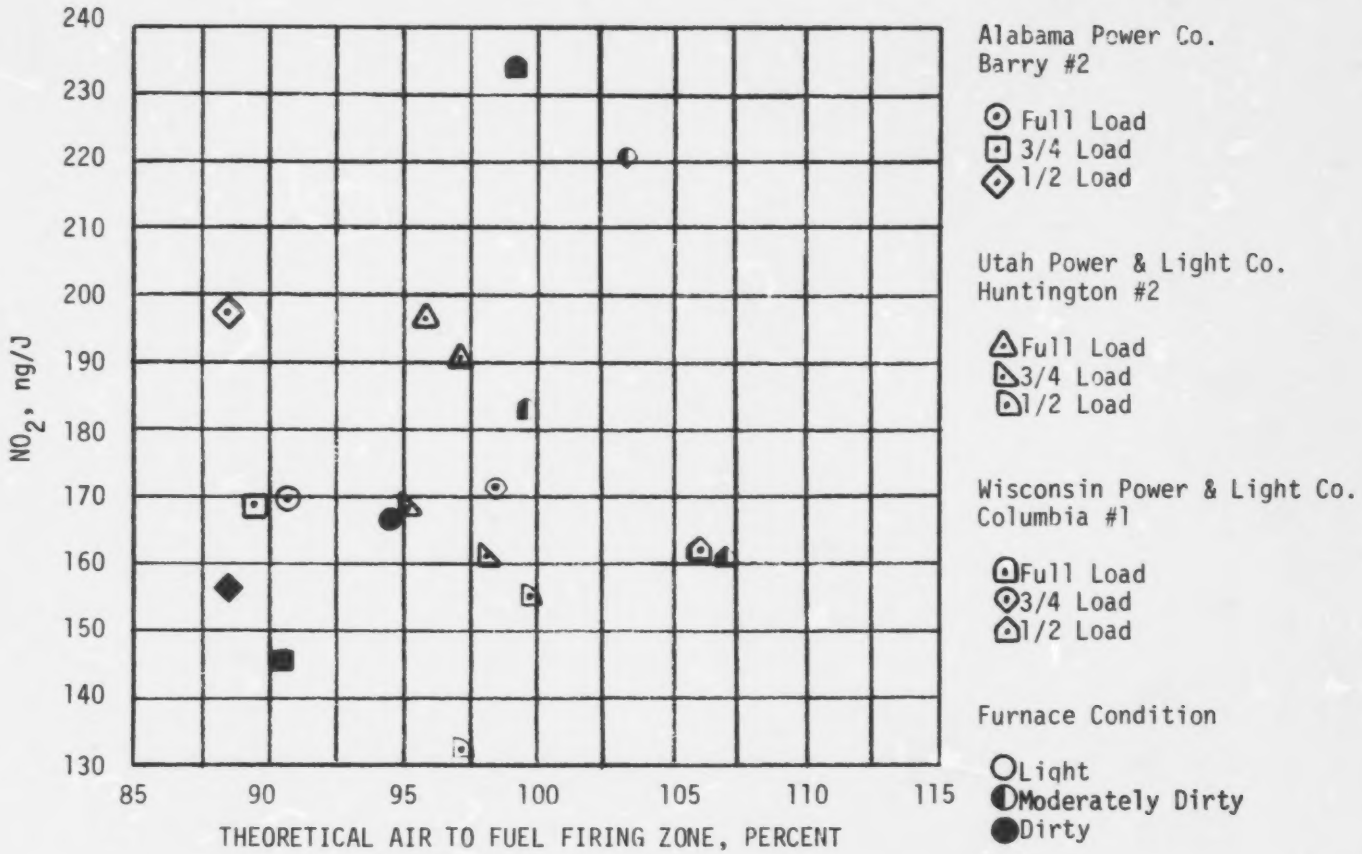


Figure 12: NO_2 vs. theoretical air, overfire air study, Test series 3

versus TA for each test in this series. This figure attempts to minimize the effect of TA and show the effect of load and furnace condition on NO_2 emission levels. Both Huntington #2 and Columbia #1 show an increase in NO_2 levels as unit load rises from half (1/2) load to full load. The effect of furnace condition on these units shows inconsistent variation in the results. Except for one half (1/2) load test, Barry #2 results also indicate an increase in NO_2 levels with increasing unit load.

For the overfire air studies, plots of CO emission levels and carbon heat loss versus TA produced the same trend that was established in the baseline operation studies. The CO levels and carbon heat losses were found to increase with decreasing theoretical air levels.

BOILER PERFORMANCE

Figure 13 is a plot of unit efficiency versus excess air for the full load tests performed on the subject units. As can be seen in Figure 13, biased firing and overfire air boiler operation did not affect unit efficiency. In a previous section it was shown that NO_2 emission levels can be reduced through the use of overfire air. Therefore, these results indicate that it may be possible to reduce NO_2 emission levels without adversely affecting boiler performance or operation.

In general, unit efficiency is found to decrease with increasing excess air. The decrease in unit efficiency with increasing excess air levels can be attributed to the increasing economizer outlet gas flows and temperatures and therefore to increased dry gas losses.

The 2 to 3 percent difference in unit efficiency between Columbia Energy Center, Unit #1 and Barry Station, Unit #2 or Huntington Station, Unit #2 can be attributed to higher dry gas losses and moisture in the fuel losses for the Columbia Energy Center's Unit #1. These higher losses are due to the type of coal being fired at Columbia Energy Center, Unit #1.

WATERWALL CORROSION COUPON EVALUATION

Thirty (30) day waterwall corrosion coupon evaluations were performed at the baseline and optimum overfire air conditions for each unit. The purpose of these evaluations was to determine what effect low excess air or staged combustion would have on waterwall tube wastage.

The method used to evaluate corrosive potential, waterwall tube wastage, in a boiler is by exposing samples of tube material to furnace conditions for finite periods of time and then measuring the weight losses. This is accomplished by inserting test probes consisting of five (5) coupons each into the furnace fuel firing zone and maintaining them at typical waterwall metal temperatures. Figure 14 depicts the type of probe and coupons used to obtain such information. This particular probe utilized air to keep the coupon at the desired temperature.

Typical instrumentation to automatically maintain the desired temperature consists of an electronic controller, and a pneumatic controller. The pneumatic controller operates as a switching device, using solenoid valves, to regulate the amount of cooling air going to the probe. The amount of air is based on a

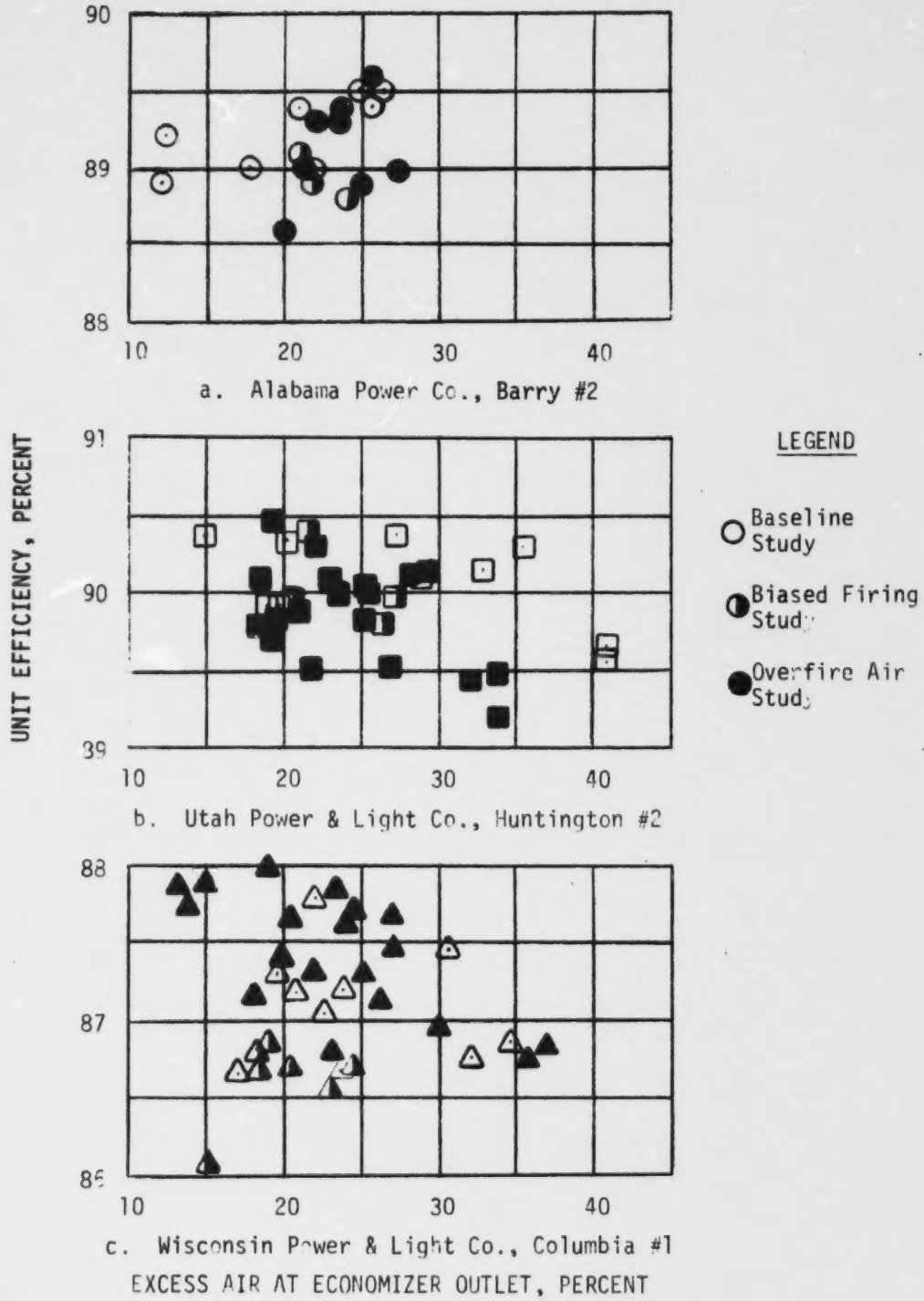


Figure 13: Unit efficiency vs. excess air

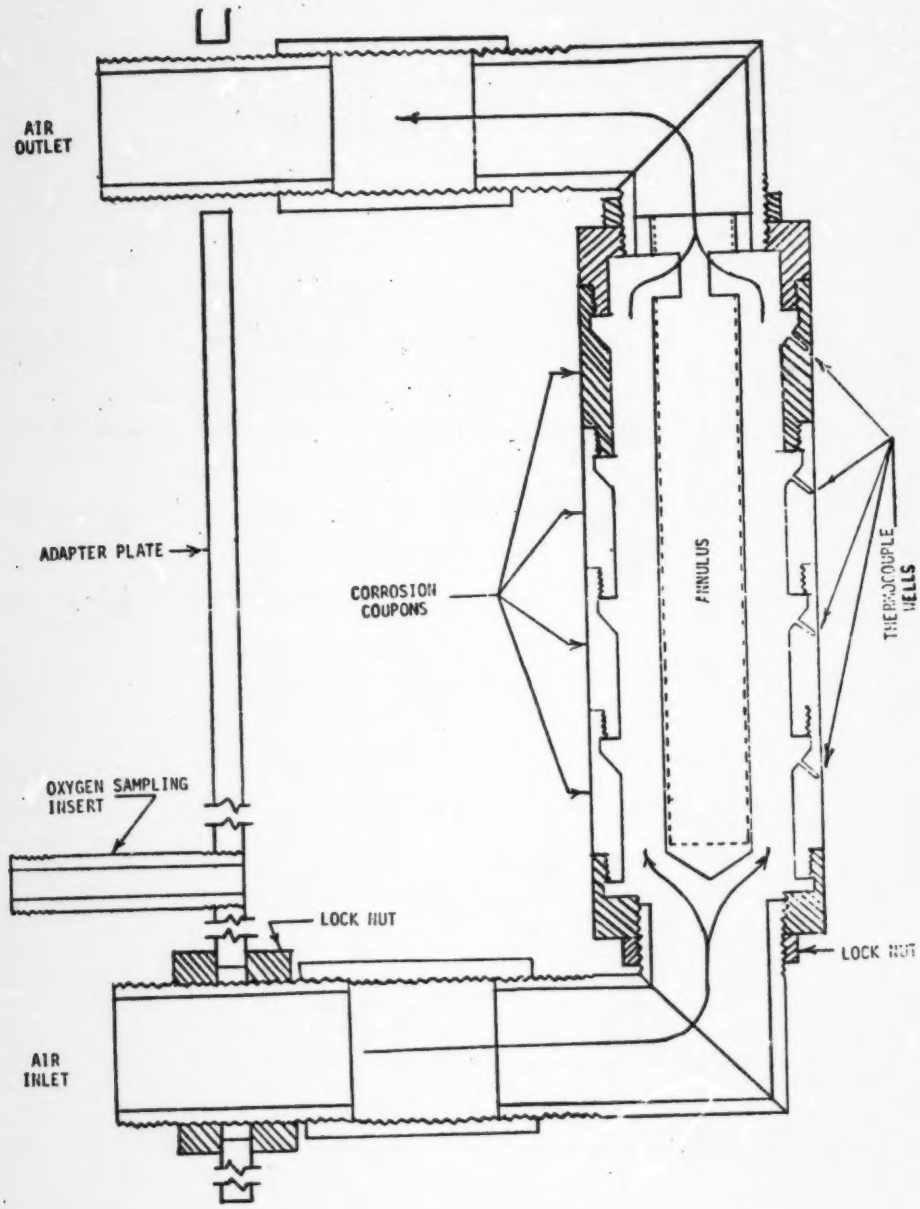


Figure 14: Corrosion Probe Assembly Drawing

signal from the electronic controller which is tied into the sensing thermocouple at the probe coupon.

At the end of the exposure period the coupons are evaluated for weight loss and visual evidence of attack. The average weight losses for the baseline and overfire air modes of boiler operation are shown in the following tables. The results indicate that waterwall tube wastage is unaffected by mode of boiler operation.

AVERAGE CORROSION COUPON WEIGHT LOSSES

Unit	Baseline Operation	Overfire Air Operation
Alabama Power Company Barry Station, Unit #2	2.6381 mg/cm^2	4.4419 mg/cm^2
Wisconsin Power & Light Co. Columbia Energy Center, Unit #1	8.0770 mg/cm^2	8.0933 mg/cm^2
Utah Power & Light Co. Huntington Station, Unit #2	3.4266 mg/cm^2	2.6357 mg/cm^2

The weight losses for the Barry Station Unit #2 and the Huntington Station Unit #2 are within the range of losses which would be expected for the oxidation of carbon steel for a thirty (30) day period. This premise was verified by control studies conducted in C-E's Kreisinger Development Laboratory.

The weight losses measured at the Columbia Energy Center Unit #1 are slightly higher than expected. One possible reason for the higher losses is that some of the probes overheated during the thirty (30) day tests. Another possible reason for the higher weight losses is that the coal being burned at Columbia Energy Center's Unit #1 is a subbituminous type coal while Barry Station Unit #2 and Huntington Station Unit #2 both burn bituminous type coals. However, the results for the Columbia Energy Center tests show the weight losses are equivalent regardless of the mode of boiler operation.

SECTION II - EPA CONTRACT 68-02-1486

OBJECTIVES

The objective of this program was to investigate the effectiveness of employing staged combustion as a method of reducing NO_x emission levels from tangentially fired boilers burning Western U.S. coals. Specifically this objective is broken down by task as follows:

TASK I - UNIT SELECTION

The basis for selection of suitable test units follows:

1. One unit (Unit "A") firing a Western U.S. subbituminous coal and a second unit (Unit "B") firing a Western U.S. bituminous coal.

2. Both units were representative of current Combustion Engineering, Inc. design employing overfire air registers in an extended windbox as a means of NO_x emission control. Neither unit required modifications with regard to those features necessary to permit evaluation of biased firing and staged combustion.

3. The size of the boilers allowed a diverse experimental program and permitted scale-up correlation of performance and emissions data to that developed under EPA Contract No. 68-02-1367 [2].

4. Two utilities willing to participate in the program which included absorbing generating losses incurred during the test program.

5. A utility which agreed to an outage of approximately one month for the installation of waterwall thermocouples on the unit that would be firing the Western U.S. subbituminous coal.

TASK II - TEST PLANNING & FABRICATION OF TEST EQUIPMENT

This task included the preparation of a detailed test program for each unit designed to investigate the effects of the following process variables and combustion modifications on NO_x, SO_x, THC, CO and unburned combustibles.

PROCESS VARIABLES

Excess Air Level
Load
Furnace Wall Deposits

COMBUSTION MODIFICATIONS

Biased Firing
Overfire Air Firing

The test program provided for documentation of the effects of the test variables on the thermal and operational performance of the boilers. It also provided for the evaluation of long term and transient operation, thermal-efficiency, slagging, fireside corrosion, flame stability and other process responses considered essential to the commercially acceptable operation of the boilers.

The following were considered in the test program planning:

1. Analytical measurements and sampling techniques.

2. Emission measurements which included NO_x, SO_x, CO, THC and O_2. CO_2 was determined by calculation.

3. Necessary analysis of fuel properties relevant to furnace operation and emissions.

4. Measurement of process variables.

The test program utilized statistical test design methods and prior experience where possible to maximize the information output from each test.

TASK III - INSTALLATION OF INSTRUMENTATION

Task III involved the installation, on each unit, of the analytical instrumentation required for calculation of CO_2 and for measurement of flue gas constituents (NO_x, SO_x, CO, THC, O_2 and unburned carbon). Also installed was the necessary instrumentation required to characterize the effects that combustion modifications have on unit performance; i.e., fireside corrosion and heat absorption. Instrumentation to determine waterwall absorption rates was installed only on Unit A. Instrumentation to determine unit absorption rates and thermal performance of the reheater, superheater, economizer and air heater sections were installed on both Units A and B.

TASK IV - BASELINE OPERATION - UNITS A & B

Similar but separate test programs were conducted on Units A & B to determine the effect of unit load, furnace wall deposits and excess air variation on baseline gaseous emission levels and unit performance. During this portion of the test program only a minimum amount of air necessary for cooling was admitted through the overfire air registers.

There were nineteen (19) tests performed for the combination of conditions indicated in Test Matrix 1.

TEST MATRIX 1

		E-1	E-2	E-3
D-1	L-1	1	2	3
	L-2		4	
	L-3	5	6	7
D-2	L-1	8	9	10
	L-2			
	L-3	11		12
D-3	L-1	13	14	15
	L-2		16	
	L-3	17	18	19

TEST CONDITIONS

Percent Excess Air

Minimum	E-1
Normal	E-2
Maximum	E-3

Furnace Wall Deposits

Clean	D-1
Moderate	D-2
Heavy	D-3

Unit Load

Maximum	L-1
3/4 Maximum	L-2
1/2 Maximum	L-3

A baseline operation waterwall corrosion rate test of a four (4) week duration was conducted after the completion of the baseline emissions test program. This study was performed at normal operating conditions with maximum load being carried whenever possible. The baseline operation corrosion rate test was conducted on both Units A & B.

TASK V - BIASED FIRING OPERATION - UNITS A & B

A program was conducted to establish the effect of operating with various fuel elevations out of service and of varying the excess air levels on gaseous emission levels and unit performance. Specifically, this portion of the program established maximum emissions control at full load and throughout the normal load range without utilizing the overfire registers; however, air was admitted through the dampers of the idle fuel nozzle elevations.

Eighteen (18) tests were conducted on Unit A at the conditions specified in Test Matrix 2.

TEST MATRIX 2

	E-1			E-2		
	L-1	L-2	L-3	L-1	L-2	L-3
B-1	1	5		11	14	
B-2	2					
B-1 B-2			8			17
B-3		6		12		
B-4	3				15	
B-3 B-4			9			
B-5				13		
B-6	4	7			16	
B-5 B-6			10			18

TEST CONDITIONS

Firing Elev. Out of Serv.

Top	B-1
Top Middle	B-2
Top Center	B-3
Bottom Center	B-4
Bottom Middle	B-5
Bottom	B-6

Unit Load

Maximum	L-1
3/4 Maximum	L-2
1/2 Maximum	L-3

Percent Excess Air

Minimum	E-1
Normal	E-2

For Unit B, there were sixteen (16) tests conducted at the conditions specified in Test Matrix 3.

TEST MATRIX 3

	E-1			E-2		
	L-1	L-2	L-3	L-1	L-2	L-3
B-1	1	4		9	12	
B-2		5		10		
B-1 B-2			7			
B-3	2				13	
B-2 B-3						15
B-4		6		11		
B-3 B-4			8			
B-5	3				14	
B-4 B-5						16

TEST CONDITIONS

Firing Elev. Out of Serv.

Top	B-1
Top Center	B-2
Center	B-3
Bottom Center	B-4
Bottom	B-5

Unit Load

Maximum	L-1
3/4 Maximum	L-2
1/2 Maximum	L-3

Percent Excess Air

Minimum	E-1
Normal	E-2

TASK VI - OVERFIRE AIR OPERATION - UNITS A & B

The overfire air operation test program was the same for both Units A & B. The test program, utilizing the overfire air system, investigated the effect of overfire air admission rates on gaseous emission levels at various unit loads and operating conditions. Those conditions which were found to be optimum from the standpoint of both effectiveness in reducing NO_x emission levels and maintaining safe unit operation were evaluated to determine their acceptability for long term operation.

The first series of tests in this portion of the program were to determine the effect on the NO_x emission levels and unit performance, when varying the overfire air rate with respect to excess air.

There were eleven (11) tests conducted at maximum load under the conditions identified in Test Matrix 4.

TEST MATRIX 4

	E-1	E-2	E-3
A-1	6	1	
A-2		2	9
A-3	7	3	
A-4		4	10
A-5	8	5	11

TEST CONDITIONS

Overfire Air Rate

None	A-1
1/4 Maximum	A-2
1/2 Maximum	A-3
3/4 Maximum	A-4
Maximum	A-5

Percent Excess Air

Minimum	E-1
Normal	E-2
Maximum	E-3

Having established the optimum overfire air rate and excess air level, this condition was used in conducting a series of fuel nozzle and overfire air register tilt variation tests.

The objective of this evaluation was to determine the effect of overfire air register tilt on the NO_x emission levels, steam temperatures and furnace wall deposits.

There were seven (7) tests performed at maximum unit load under the conditions listed in Test Matrix 5.

TEST MATRIX 5

	F-1	F-2	F-3
R-1	12	13	
R-2	14	15	16
R-3		17	18

TEST CONDITIONS

Fuel Nozzle Tilt

Maximum Minus	F-1
Horizontal	F-2
Maximum Plus	F-3

Overfire Air Register Tilt

Maximum Minus	R-1
Horizontal	R-2
Maximum Plus	R-3

The objective of the final series of tests for this test program was to determine the effect on NO_x emission levels and unit performance when operating at the previously established optimum conditions, while varying unit load and furnace wall deposits.

There were six (6) tests conducted at the conditions identified in Test Matrix 6.

TEST MATRIX 6

	OC-1	
	D-1	D-3
L-1	19	20
L-2	21	22
L-3	23	24

TEST CONDITIONS

Unit Load

Maximum	L-1
3/4 Maximum	L-2
1/2 Maximum	L-3

Furnace Wall Deposits

Clean	D-1
Heavy	D-3

Unit Operating Conditions

Optimum Conditions	OC-1

To determine the effect of long term and transient overfire air operation on the furnace waterwall wastage rate, a waterwall corrosion study was conducted for a four (4) week period. This study was conducted at optimum conditions for NO_x reduction, as determined in the previously outlined test program, with maximum load being maintained whenever possible.

TASK VII - PREPARATION OF TEST REPORT AND ANALYSIS OF DATA

The test report includes all data obtained during the test program and the analysis of that data.

Specific areas of analysis and reporting are:

1. The reporting of emissions data with respect to modes of operation and coal type.

2. The analysis of emission data with respect to Contract 68-02-1367, for a unit that is equipped with a modified overfire air system.

3. The reporting of emission data with respect to unit performance.

4. The reporting of the corrosion probe study with respect to overfire air operation and coal type.

5. The analysis of corrosion probe wastage data with respect to Contract 68-02-1367.

6. The scale-up considerations for design of new overfire air systems resulting from this study and Contract 68-02-1367.

7. The possible changes to cost estimates for overfire air systems in new and existing boilers if this study indicates previously developed cost estimates based on Contract 68-02-1367 should be revised.

DISCUSSION

TASK I - UNIT SELECTION

The two units selected for participation in this test program were:

UNIT A - Wisconsin Power & Light Co.
Columbia Energy Center, Unit #1

UNIT B - Utah Power & Light Co.
Huntington Canyon, Unit #2

These units are representative of current Combustion Engineering, Inc. boiler design. Both units incorporate overfire air registers in an extended windbox as a means of NO_x emission control. A typical windbox arrangement for one corner of a unit is shown in Figure 15. The primary air, which conveys the coal, is introduced through the center portion of the tilting coal nozzles. Secondary air is introduced selectively through openings at the periphery of the coal nozzles and/or through the air nozzles. Windbox air dampers located in the fuel and air compartments regulate the distribution of the secondary air. The quantity of air flow is controlled by the induced draft and forced draft fan system [7].

Unit A, Columbia Energy Center, Unit #1, is a controlled circulation, balanced draft, radiant, reheat boiler firing pulverized coal through six elevations of tilting tangential fuel nozzles. Unit capacity at maximum continuous rating (MCR) is 479 kg/s (3,800,000 LBS/HR) main steam flow at a superheat outlet temperature and pressure of 541°C (1005°F) and 18.1 MPa (2620 PSIG), respectively. The Columbia Energy Center, Unit #1 fires a Montana Rosebud seam subbituminous 'C' coal. A side elevation of Columbia Energy Center, Unit #1 is shown in Figure 16.

Unit B, Huntington Canyon, Unit #2, is also a controlled circulation, balanced draft, radiant, reheat boiler firing pulverized coal through five elevations of tilting tangential fuel nozzles. The unit capacity at the maximum continuous rating (MCR) is 382 kg/s (3,036,000 LBS/HR) main steam flow with a superheat outlet temperature and pressure of 541°C (1005°F) and 18.2 MPa (2645 PSIG), respectively. This unit fires a high Volatile 'B' bituminous coal supplied from the nearby Peabody Coal Company's Deer Creek Mine. A side elevation of Huntington Canyon, Unit #2 is shown in Figure 17.

In both units, superheat outlet temperatures are controlled by spray desuperheating. Reheat outlet temperatures are controlled by fuel nozzle tilt and spray desuperheating.

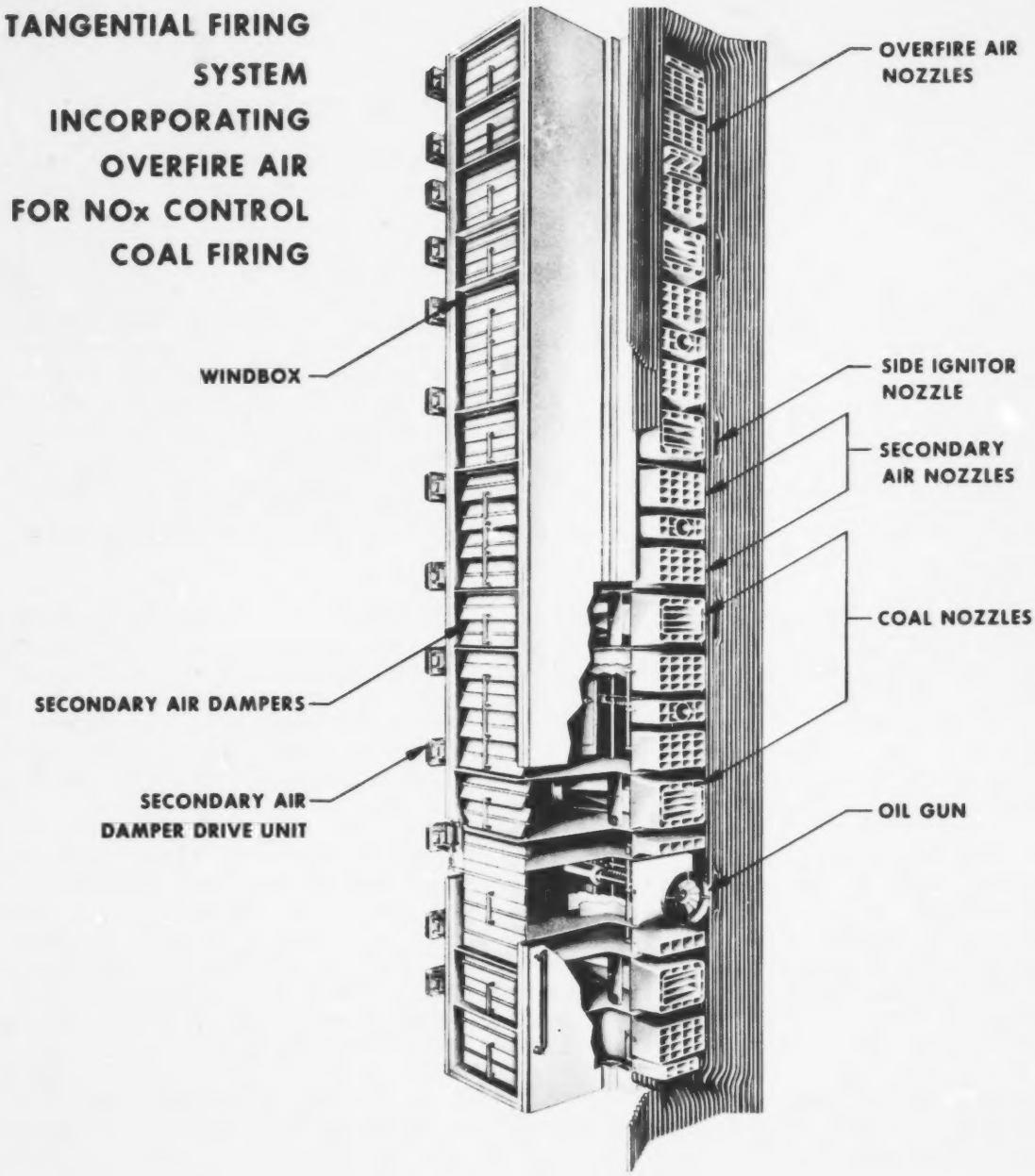


Figure 15: Typical windbox of tangential firing system

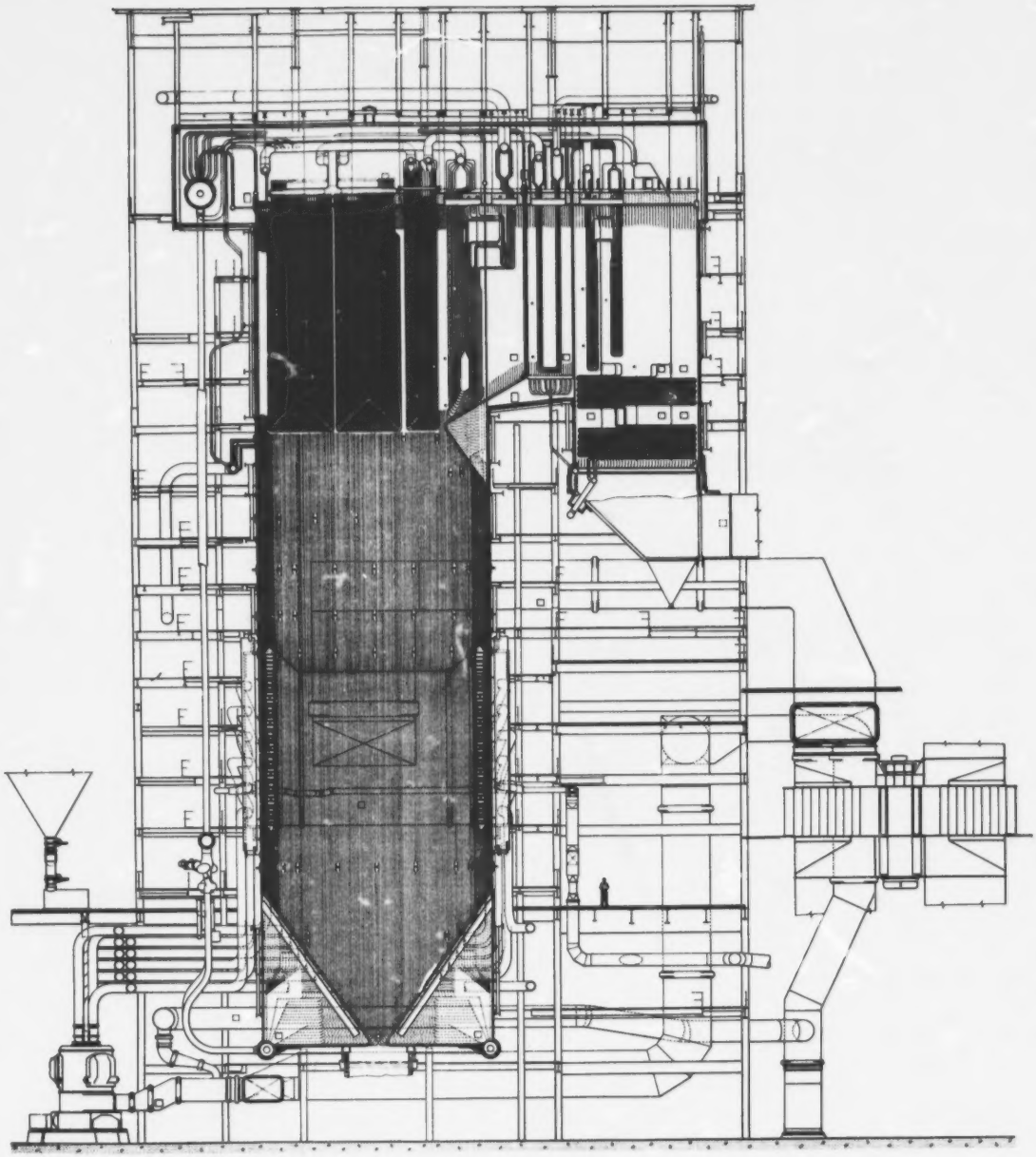


Figure 16. Unit side elevation, Wisconsin Power and Light Company, Columbia Energy Center No. 1

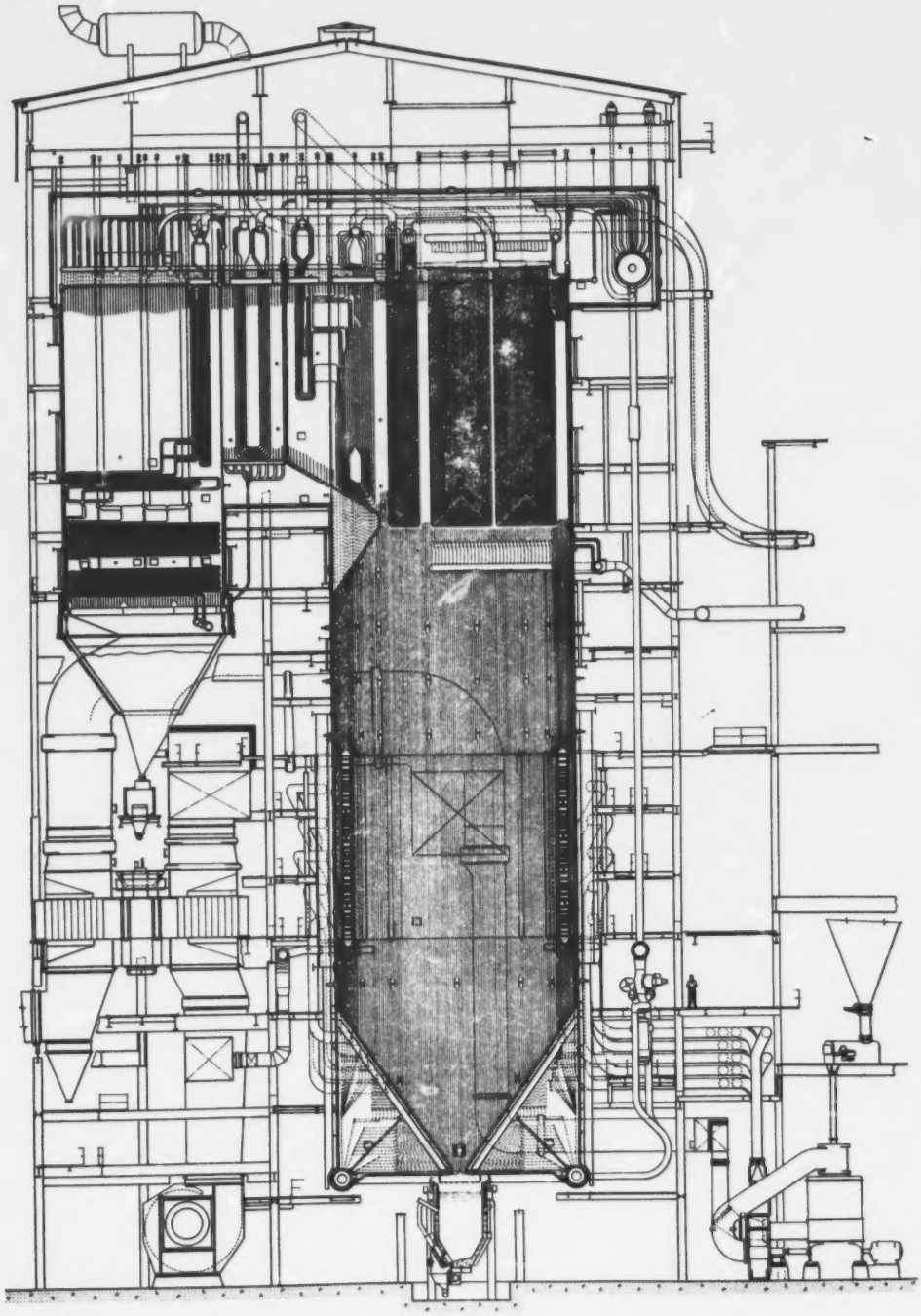


Figure 17. Unit side elevation, Utah Power and Light Company Huntington Station No. 2

TASK II - TEST PLANNING & FABRICATION OF TEST EQUIPMENT

The test program was designed to investigate the effect of excess air level, unit load, furnace wall deposits, biased firing, and overfire air operation with respect to NO_x and related gaseous emission levels, furnace waterwall corrosion and unit performance. The instrumentation required to achieve the above mentioned goals included such items as fabrication of corrosion probes, probe control systems, gas temperature and sampling probes, calibration of thermocouples, analyzers and pressure gauges and the packaging of equipment for shipping to the test sites.

At the test sites, flue gas samples for the determination of NO_x, SO_x, THC and CO were obtained from the boiler economizer outlet ducts. The percent oxygen in the flue gas entering and leaving the air preheaters was also obtained for the determination of air preheater leakage and unit efficiency.

The type of instrumentation used in determining the emission concentrations and the general locations of these instruments are described in the discussion of Task III - Installation of Instrumentation. Unit steam and gas-side performance was monitored using calibrated thermocouples, pressure gauges and manometers as required. The general locations of these instruments are also described in the discussion of Task III - Installation of Instrumentation. Type E chordal thermocouples were installed in the furnace waterwalls at Wisconsin Power and Light Co.'s, Columbia Energy Center, Unit #1.

Coal samples were obtained during each test for later analysis. Fuel analysis, unit emission levels, steam flow rates, absorption rates, gas and air weights and efficiencies were calculated for each test. The calculating methods and procedures used are listed in the discussion of Task III - Installation of Instrumentation.

The test program documented and discussed in detail all tools and techniques regarding analytical measurements and sampling techniques and calculating procedures used.

TASK III - INSTALLATION OF INSTRUMENTATION

Instrumentation necessary to conduct the baseline, biased firing and overfire air test programs on the selected units was installed and calibrated. This instrumentation consisted of the following:

MEASUREMENT	INSTRUMENT OR METHOD	LOCATION OF MEASUREMENT OR CALCULATION PROCEDURE
<u>Flue Gas Constituents</u>		
Nitrogen Oxides - NO_x	Chemiluminescence Analyzer	Economizer Gas Outlet
Carbon Monoxide - CO	Infrared Analyzer	Economizer Gas Outlet
Total Hydrocarbons - THC	Flame Ionization Analyzer	Economizer Gas Outlet

MEASUREMENT	INSTRUMENT OR METHOD	LOCATION OF MEASUREMENT OR CALCULATION PROCEDURE
Flue Gas Constituents (Cont.)		
Oxygen - O_2	Paramagnetic Analyzer	Economizer Gas Outlet and Air Heater Gas Inlet and Outlet
Sulfur Dioxide - SO_2	Wet Chemistry	Economizer Gas Outlet
Carbon Dioxide - CO_2	Calculated	Combustion Calculations
Unburned Combustibles	Cyclone Dust Collector ASME Dust Collector	Economizer Gas Outlet - Unit A Air Heater Gas Outlet - Unit B
Steam and Water Flows		
Feedwater	Mercury Manometer	Feedwater Orifice
SH Desuperheat Spray	Calculated	Heat and Mass Balance
RH Desuperheat Spray	Calculated	Heat and Mass Balance
Reheat	Calculated	Heat and Mass Balance
Superheat	Calculated	Heat and Mass Balance
Air and Gas Flows		
Total Flue Gas	Calculated	Heat and Combustion Calculations
Total Air	Calculated	Heat and Combustion Calculations
Overfire Air	Calculated	Mass Balance
Air Heater Leakage	Calculated	Mass Balance
Miscellaneous Flows		
Coal	Coal Scales	Coal Feeders - Plant Instrumentation
Pressures		
Steam and Water	Calibrated Gauges	Economizer Inlet Drum Superheat Outlet Reheat Inlet

MEASUREMENT	INSTRUMENT OR METHOD	LOCATION OF MEASUREMENT OR CALCULATION PROCEDURE
Pressures (Cont.)		
		Reheat Outlet Superheat Spray Water Reheat Spray Water High Pressure Heater Shell Side
Air and Gas	Plant Instrumentation	FD Fan Outlet AH Air Inlet AH Air Outlet Windbox Furnace Economizer Outlet AH Gas Inlet AH Gas Outlet ID Fan Inlet
Temperatures		
Steam and Water	Calibrated Stainless Steel Type E Well and Type E Button Thermocouples	Economizer Inlet Economizer Outlet SH Desuperheat Inlet SH Desuperheat Outlet Superheat Outlet RH Desuperheat Inlet RH Desuperheat Outlet Reheat Outlet SH DESH Spray Water RH DESH Spray Water HP Heater Inlet Steam HP Heater Drain HP Heater FW Inlet HP Heater FW Outlet
	Calibrated Stainless Steel Sheathed Type E Chordal Thermocouples	Furnace Waterwall Tubes
Air and Gas	Type E Thermocouples	Air Heater Gas Inlet Air Heater Gas Outlet Air Heater Air Inlet Air Heater Air Outlet
Miscellaneous		
Coal Samples	ASTM Procedures	Coal Feeders
Wall Deposit Patterns	Visual Observation	Furnace Waterwalls
Waterwall Corrosion	Corrosion Probes	Front Furnace Waterwall

The same instrumentation and measurements as required in support of the baseline, biased firing and overfire air test programs on Unit A were utilized on Unit B, with the exception of the chordal thermocouples installed in the furnace waterwall tubes.

All test measurements were supplemented by monitoring and recording the normally available plant operating instrumentation.

COLUMBIA ENERGY CENTER, UNIT #1

TASKS IV, V & VI - TEST DATA ACQUISITION AND ANALYSIS

Wisconsin Power and Light Company's, Columbia Energy Center, Unit No. 1 has two "hot precipitators", i.e. the electrostatic precipitators are located between the boiler economizer outlets and the air preheater gas inlets. The use of the hot precipitators necessitated the sampling of the flue gas at three locations; economizer outlet, air preheater gas inlet, and air preheater gas outlet.

Flue gas samples for determination of NO_2, CO, O_2 and THC emission levels were obtained from each of the two economizer outlet ducts. The flue gas samples were drawn using a twelve (12) point grid in each duct. The SO_2 sample was drawn from a single point in the left economizer outlet duct using a heated sample line. The fly ash sample for carbon loss analysis was also obtained from a single point in the left economizer outlet duct.

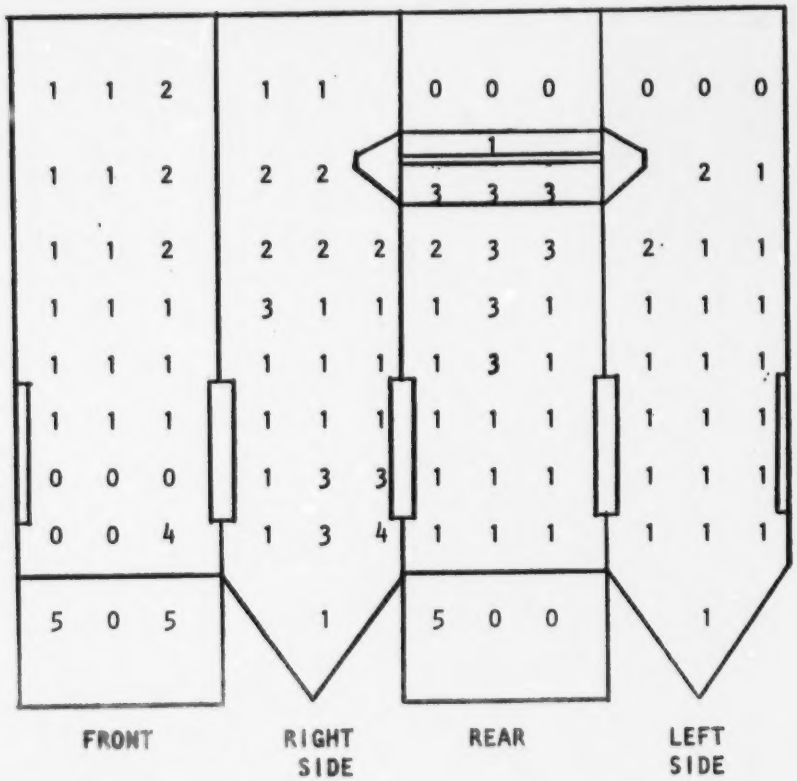
The percent oxygen in the flue gas entering and leaving the two air preheaters was drawn from an eighteen (18) point grid in each air preheater gas inlet and outlet duct. The grids were arranged so as to allow sampling on centroids of equal area. The percent oxygen in the flue gas entering and leaving the air preheaters is required for the determination of the air preheater leakage. The percent oxygen at these two points plus the percent oxygen in the flue gas leaving the economizer is used in the calculation of unit efficiency.

Visual observations of the furnace waterwalls were recorded for each test. However, visual observations of the furnace waterwalls were hampered due to the insufficient number and location of the observation doors. Typical wall deposit patterns taken during clean, moderate and heavy furnace slagging conditions at full load operation are shown on Figures 18, 19 and 20. These slag patterns are typical for all modes of boiler operation.

Chordal thermocouples were installed in the furnace waterwalls of Columbia Energy Center, Unit No. 1. The chordal thermocouples are utilized to determine the waterwall absorption rates and are therefore useful in monitoring furnace performance. The use of the chordal thermocouples is further explained in a separate subsection, Furnace Performance.

The Coal Feeders at Columbia #1 are pressurized. As a result, coal samples were initially obtained from the conveyor belts feeding the coal bunkers, with one sample being obtained for each test for later analysis. The samples could only be obtained when the bunkers were being filled, which was two to three times per day. This sampling method was not considered desirable, as it was impossible to know if the coal being fed to the coal bunkers was representative of the coal being burned during any one test. Gate valves were installed in the pipes feeding the coal from the bunkers to the feeders. With the installation of the gate valves, samples were obtained from each coal feeder during

FURNACE WATERWALL DEPOSIT PATTERN



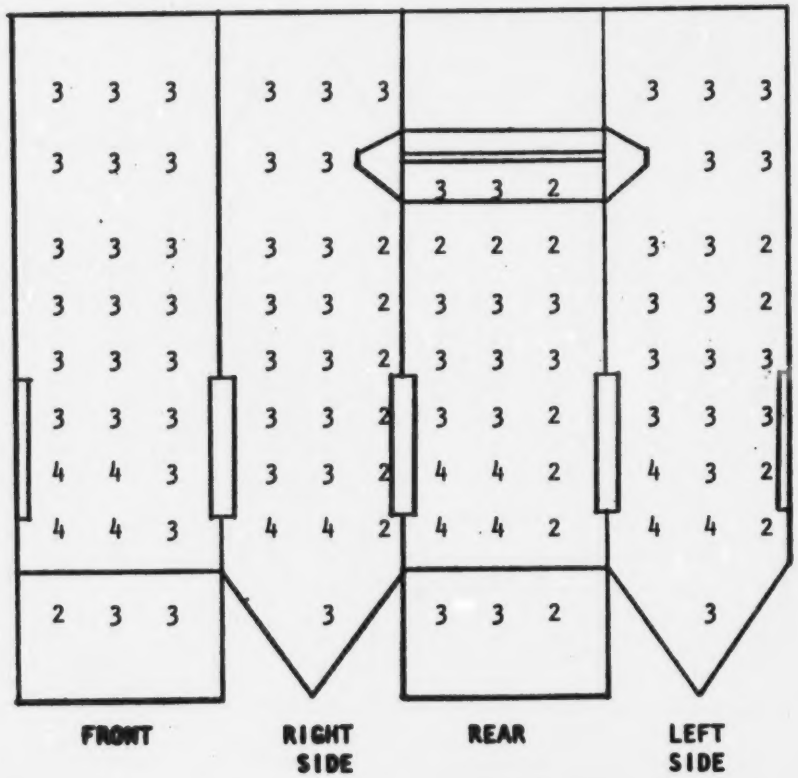
KEY

NO ASH	0
FUZZY <13 MM	1
LIGHT 13 MM - 25 MM	2
LIGHT TO MED. 25 MM - 50 MM	3
MED. TO HEAVY 50 MM - 100 MM	4
HEAVY >100 MM	5
RUNNING SLAG	6

NOTE: 25.4 MM = 1 INCH

Figure 18: Furnace waterwall deposit pattern, clean furnace

FURNACE WATERWALL DEPOSIT PATTERN



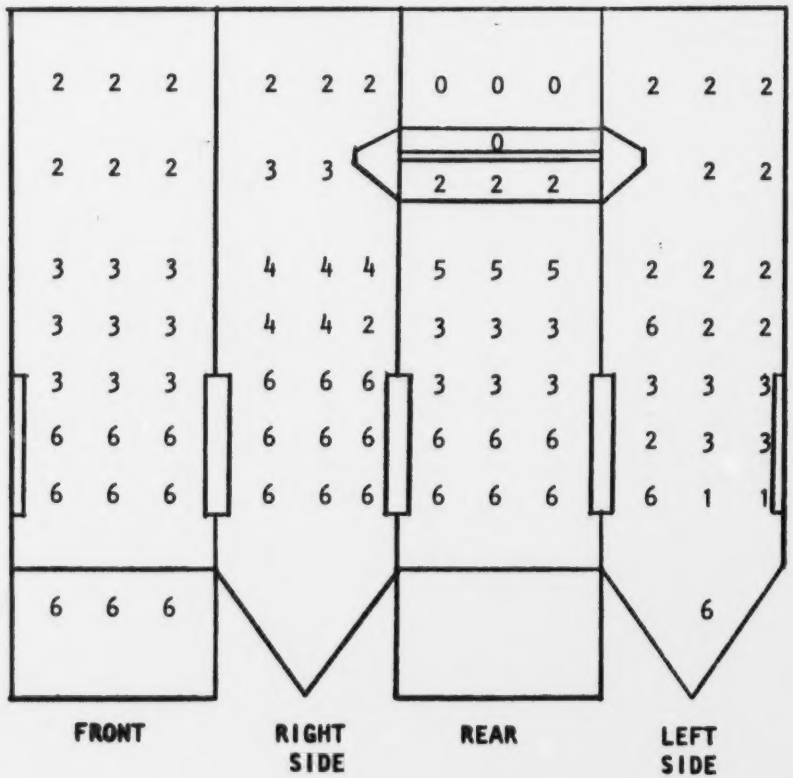
KEY

NO ASH	0
FUZZY <13 MM	1
LIGHT 13 MM - 25 MM	2
LIGHT TO MED. 25 MM - 50 MM	3
MED. TO HEAVY 50 MM - 100 MM	4
HEAVY >100 MM	5
RUNNING SLAG	6

NOTE: 25.4 MM = 1 INCH

Figure 19: Furnace waterwall deposit pattern, moderate slag furnace

FURNACE WATERWALL DEPOSIT PATTERN



KEY

NO ASH	0
FUZZY <13 MM	1
LIGHT 13 MM - 25 MM	2
LIGHT TO MED. 25 MM - 50 MM	3
MED. TO HEAVY 50 MM - 100 MM	4
HEAVY >100 MM	5
RUNNING SLAG	6

NOTE: 25.4 MM = 1 INCH

Figure 20: Furnace waterwall deposit pattern, heavy slag furnace

each test and were blended to form a composite sample for each test.

The test data and results for the tests conducted at Wisconsin Power and Light Company's, Columbia #1 are tabulated in Appendix A. Summaries of the emissions test data for the baseline, biased firing and overfire air operation studies are tabulated on Sheets A-1 through A-6. During some of the testing in March and May of 1976, CO emission levels were not monitored due to malfunctioning of the CO analyzer. These tests are reported as not available, (NA), on the emissions test data summary sheets. Unit Performance test data for the three studies are tabulated on Sheets A-7 through A-13. The calculated unit performance test results are tabulated on Sheets A-14 through A-21. Unit efficiency is determined using the Heat Losses Method (ASME Power Test Code, PTC 4.1-1964, reaffirmed 1973). Sheets A-22 through A-35 are a tabulation of the average waterwall absorption rates, as measured at each chordal thermocouple for each test. A set of unit board and computer data was obtained for each test and is tabulated on Sheets A-36 through A-56.

All test data and results are reported in SI Metric units, with the exception of the board and computer data. The board and computer data is reported in the engineering units provided by plant instrumentation.

The thirty (30) day waterwall corrosion coupon evaluations were conducted using a specially designed probe consisting of four individual coupons. The waterwall corrosion coupon evaluations are described and discussed under a separate subsection in this report.

TASK IV - BASELINE OPERATION STUDY

Load and Excess Air Variation - Clean Furnace

Tests 1 through 7 were performed to determine the effect of varying excess air on unit emission levels and performance. These tests were conducted at three unit loads with clean furnace conditions. The slag observed on the furnace waterwalls ranges from 0 to 25.4 mm (1 in.) in thickness.

Initially, maximum and minimum excess oxygen levels of six (6) percent and three and one-half (3.5) percent at the economizer outlet were set by Wisconsin Power and Light Co. as acceptable modes of unit operation at full load. Wisconsin Power and Light later requested that the minimum excess oxygen limit be raised to four (4) percent. At reduced loads these limits were slightly higher. On a few occasions, excess oxygen values as low as two and one-half (2.5) percent were experienced, when measured using test instrumentation. The limits set by Wisconsin Power and Light were exceeded on those occasions due to a discrepancy between plant and test instrumentation. The Plant oxygen alalyzer was being used to monitor and control unit operations. At times the Plant analyzer was reading approximately one percent (1%) higher than test instrumentation.

During initial testing of Columbia, Unit No. 1, mechanical stops on the induced draft fans prevented the unit from reaching full load during high excess air operation tests. The mechanical stops were changed during a unit outage in June, 1976 enabling the unit to achieve full load during subsequent high excess air operation tests.

Comparison of NO_2 emission levels with unit load shows NO_2 levels were generally higher at half load than at full load. This might be attributed to the fact that the excess air levels are higher at half load than at full load.

CO emission levels are found to be higher at full load unit operation than at half load operation. This can be attributed to the fact that at lower loads the unit operates at higher excess air levels.

The effect of excess air level and unit loading on unit efficiency, carbon heat loss, unburned hydrocarbons and sulfur dioxide emission levels is discussed in conjunction with the other baseline tests.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Furnace Condition
1	441	322.9	4.8	20.7	117.8	86.95	Clean
2	442	260.2	4.8	21.8	118.9	87.49	Clean
3	400	303.7	5.4	34.7	131.4	86.28	Clean
4	334	246.3	NA	35.6	132.5	87.35	Clean
5	267	291.2	1.5	27.7	126.7	87.94	Clean
6	269	335.2	1.7	37.5	136.2	87.05	Clean
7	268	333.8	2.2	43.5	141.4	87.23	Clean

Load and Excess Air Variation - Moderately Dirty Furnace

Tests 8 through 12 were conducted with a moderately dirty furnace. The slag observed on the furnace waterwalls ranged from 25.4 mm (1 in.) to 76.2 mm (3 in.) in thickness and was in a plastic state in the thicker areas. The excess air levels and unit loads were allowed to vary per the test program.

The NO_2 emission levels for tests 8 through 12 are shown in the following table. Examination of this table shows only small changes in emission levels for the full load tests. This could be due to small changes in excess air levels. For the half load tests there is a distinct change in NO_2 level with a change in excess air level. At similar excess air levels, the full load tests have higher NO_2 levels than the half load tests.

At similar unit loads, CO emission levels do not show any appreciable change with changes in excess air levels. Comparison of full and half load tests show CO emission levels to be higher at full load. As with tests 1 through 7, this difference can be partially attributed to the fact that the boiler operates at higher excess air levels at half load.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Furnace Condition
8	427	295.7	5.1	19.4	116.5	87.04	Moderate
9	432	290.2	4.9	23.7	120.7	86.85	Moderate
10	394	310.6	5.1	30.6	127.5	86.93	Moderate
11	263	270.5	1.5	20.4	117.2	87.26	Moderate
12	265	368.3	1.9	52.5	145.0	86.41	Moderate

Load and Excess Air Variation - Dirty Furnace

Tests 13 through 19 were conducted with heavy furnace wall deposits. Furnace wall deposits ranged from 50.8 mm (2 in.) to 101.6 mm (4 in.) thick. The slag was usually in a plastic state and at times built up to 305 mm (12 in.) to 610 mm (24 in.) thick on the lower furnace walls. This buildup was caused by the slag slowly flowing down the furnace walls. The excess air levels and unit loads were varied per the test program.

As shown in the following table, there is a correlation between NO_2 emission levels and excess air level at half load. At full load this correlation is not evident, as the NO_2 at the low excess air level is higher than expected.

As with the earlier baseline tests, the CO levels for the half load tests are lower than for the full load tests.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Furnace Condition
13	432	315.7	NA	17.1	114.3	86.57	Heavy
14	426	309.5	4.9	22.6	119.7	76.75	Heavy
15	397	334.3	5.6	32.2	129.0	76.20	Heavy
16	329	252.9	NA	35.7	132.5	85.56	Heavy
17	264	294.6	1.2	26.1	122.8	87.65	Heavy
18	267	347.7	1.3	39.5	134.3	87.15	Heavy
19	263	369.2	1.4	54.8	144.6	86.23	Heavy

Analysis of Results

The changes in NO_2, CO and carbon heat loss versus theoretical air to the fuel firing zone are shown on Figures 21, 22 and 23. These parameters are plotted versus theoretical air to the fuel firing zone rather than the total excess air. For the baseline operation study the TA is essentially the same as the total air.

Figure 21 shows that NO_2 correlates reasonably well with TA. Increasing TA results in increasing NO_2 emission levels. This correlation is in agreement with other research, which has shown that NO_2 emission levels are proportional to the concentration of oxygen available for combustion. Comparison of full load and half (1/2) load test at similar TA shows that the half (1/2) load tests have lower NO_2 levels. The two three-quarter (3/4) load tests shown on Figure 21 do not correlate with the full or half (1/2) load tests with respect to TA or unit load.

With the exception of one supposedly clean test, furnace waterwall deposits appear to have some effect on NO_2 emission levels. As Figure 21 indicates, those tests performed with heavier furnace waterwall deposits generally have higher NO_2 levels.

While the data plotted is not sufficient proof to the above statement, it does support the argument that NO_2 emission levels are affected by furnace waterwall deposit conditions.

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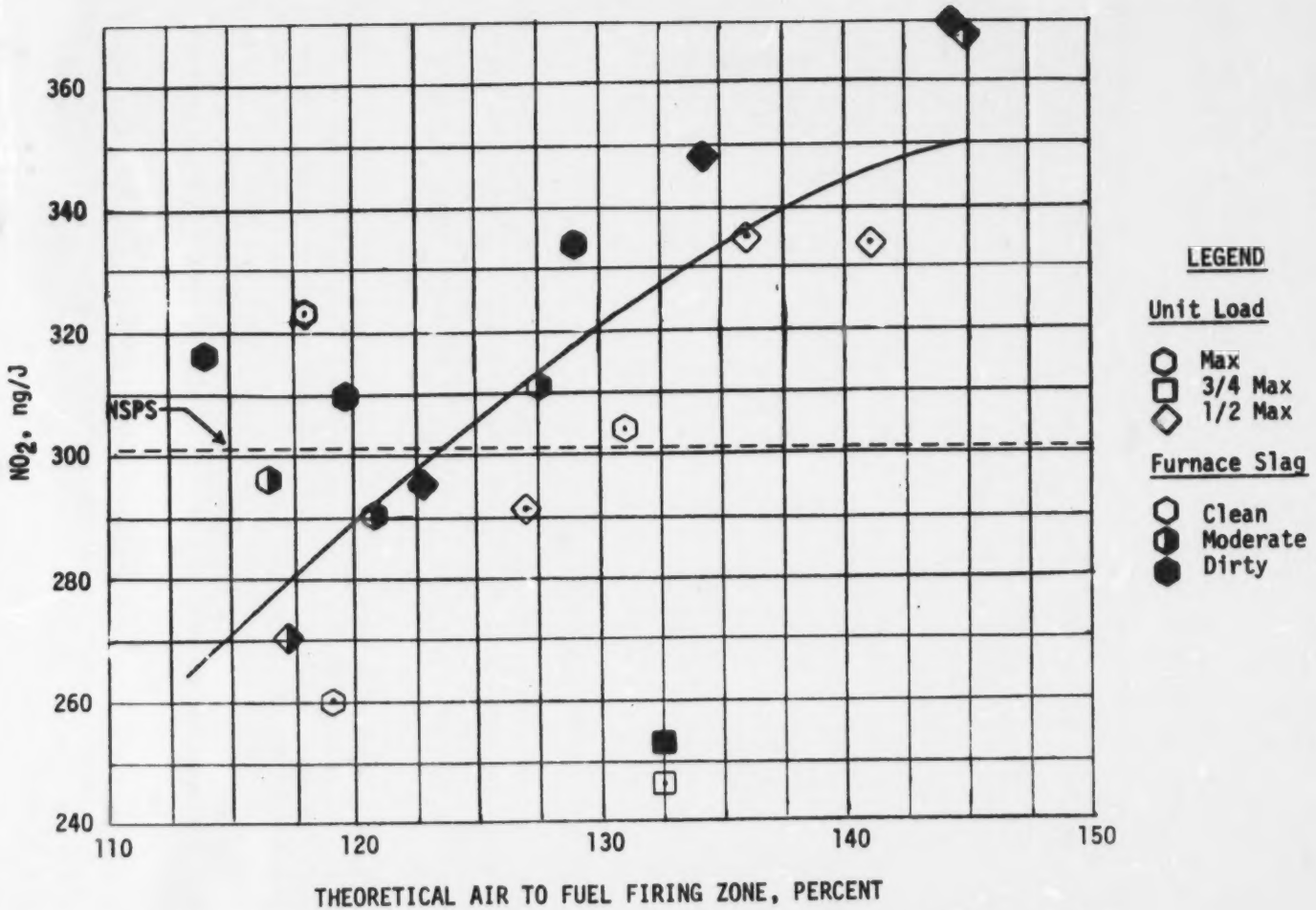

Figure 21: NO_2 vs. theoretical air to fuel firing zone, baseline study

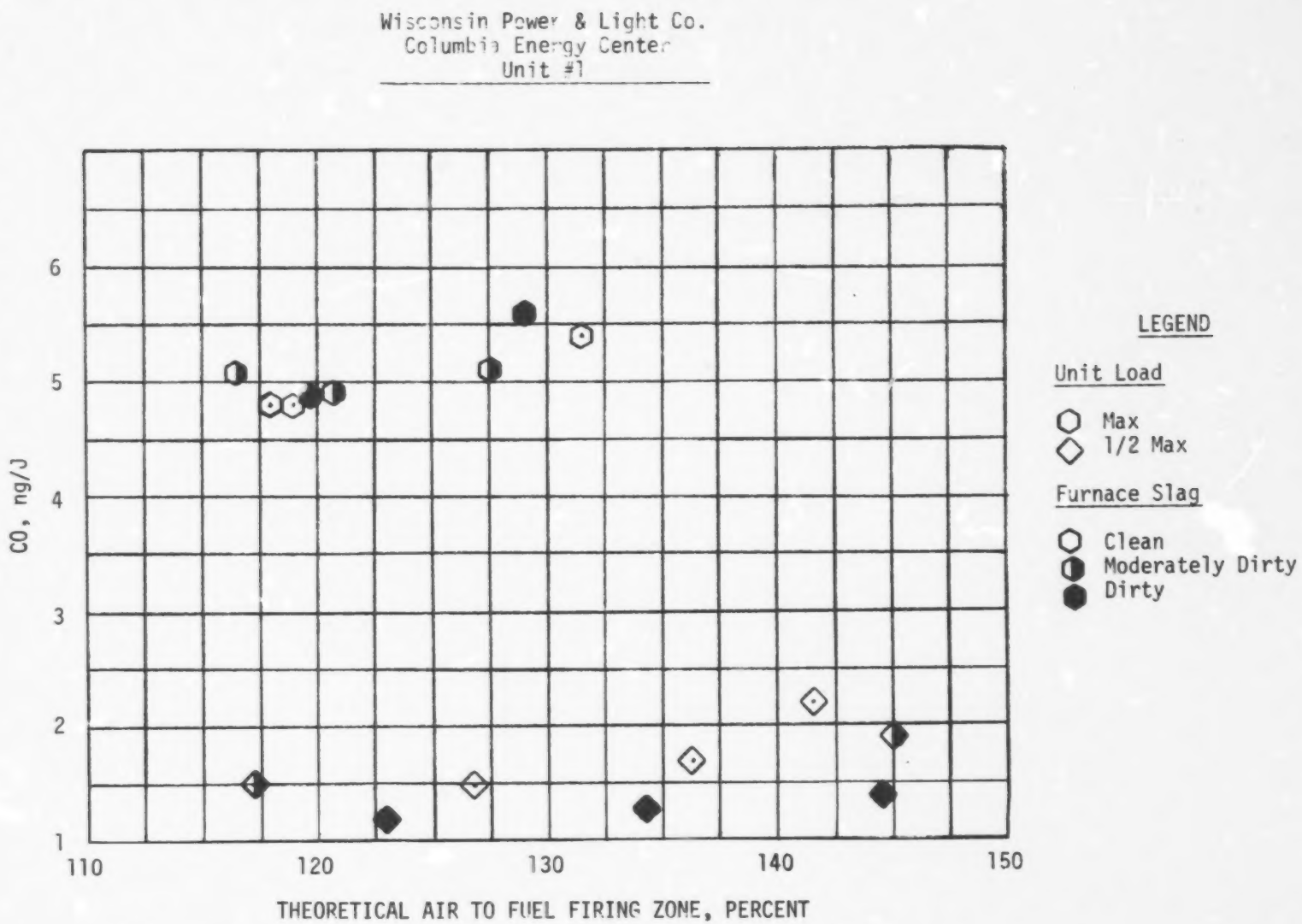

Figure 22: CO vs. theoretical air to fuel firing zone, baseline study

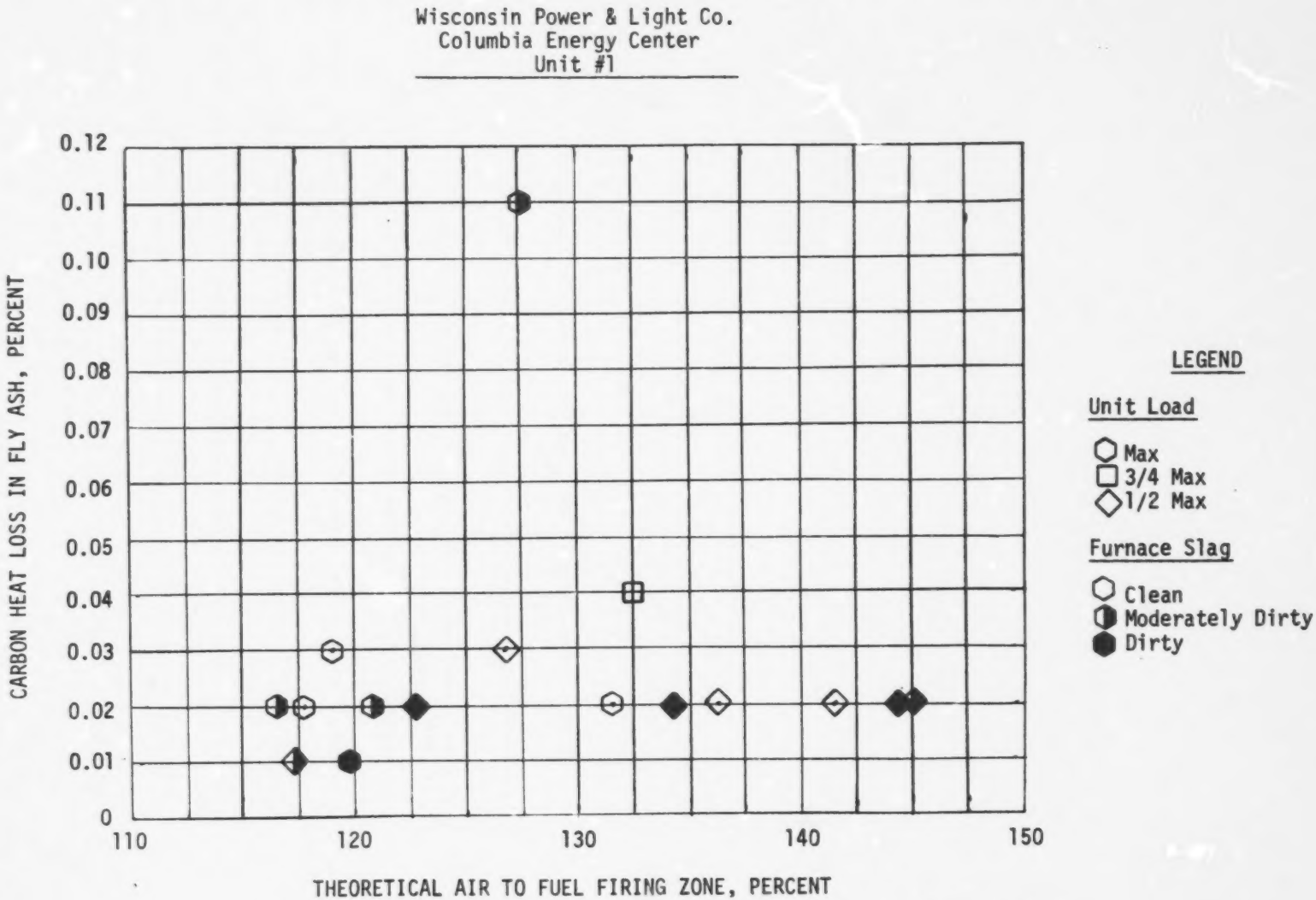

Figure 23: Carbon heat loss vs. theoretical air, baseline study

Figure 22 does not show any variation in CO emission levels with changes in TA. However, it does show that unit loading has a significant effect on CO emission levels. The CO levels at full load are approximately five (5) times the CO levels at half (1/2) load. It should be noted that the half (1/2) load tests were performed in May, 1976, while the full load tests were performed in March, 1976. Besides changes in tilt, the only other significant change other than load was that the fuel and auxiliary nozzle compartment damper settings were changed. The fuel nozzle compartment dampers were opened from an average 50% open to 100% open, while the auxiliary nozzle compartment dampers were closed from approximately 100% open to approximately 50% open. Whether this would have any effect on CO emission levels is unknown.

The percent carbon heat loss in the fly ash versus theoretical air to the fuel firing zone is shown in Figure 23. The carbon heat loss values for tests 13 and 15 have not been plotted on Figure 23, as they were too high to be shown on this figure. With the exception of these two tests and the one high test shown, carbon heat loss appears to be unaffected by variations in TA, unit load and furnace waterwall deposits.

Figure 24 is a plot of unit efficiency versus excess air at the economizer outlet. This figure indicates that unit efficiency is inversely proportional to excess air at the economizer outlet. By examining the full load and half (1/2) load test separately, the decrease in unit efficiency with increasing excess air at the economizer outlet is more apparent.

The SO_2 emission levels were monitored for each test and are reported on Sheets A1 and A2. No correlation was evident between SO_2 emission levels and excess air, unit loading or furnace waterwall deposits. It was not possible to control the SO_2 emission levels as they are more a function of the sulfur content of the fuel rather than the mode of boiler operation.

Unburned hydrocarbon emission levels were monitored and were found to be at such low levels as to be unmeasurable.

A thirty (30) day baseline waterwall corrosion coupon test was conducted in April and May of 1975. Boiler operation was normal with full load being maintained as much as possible. The waterwall corrosion coupon test is discussed in the section, Waterwall Corrosion Coupon Evaluation.

TASK V - BIASED FIRING STUDY

Fuel Elevations Out of Service Variation

Eighteen (18) tests were conducted at Columbia Energy Centers', Unit #1 to determine the effect on NO_2 emission levels when taking various fuel elevations out of service (biased firing). These tests were performed at three unit loadings and two excess air levels.

As shown by the data in the following table, the NO_2 emission levels are lowest with the top and/or top middle elevation of fuel nozzles out of service (Tests 1, 2, 5, 8, 14 and 17). When comparing tests with similar operating conditions (Tests 5 vs. 14 or 8 vs. 17), it can be seen that increasing excess air level results in increasing NO_2 emission levels.

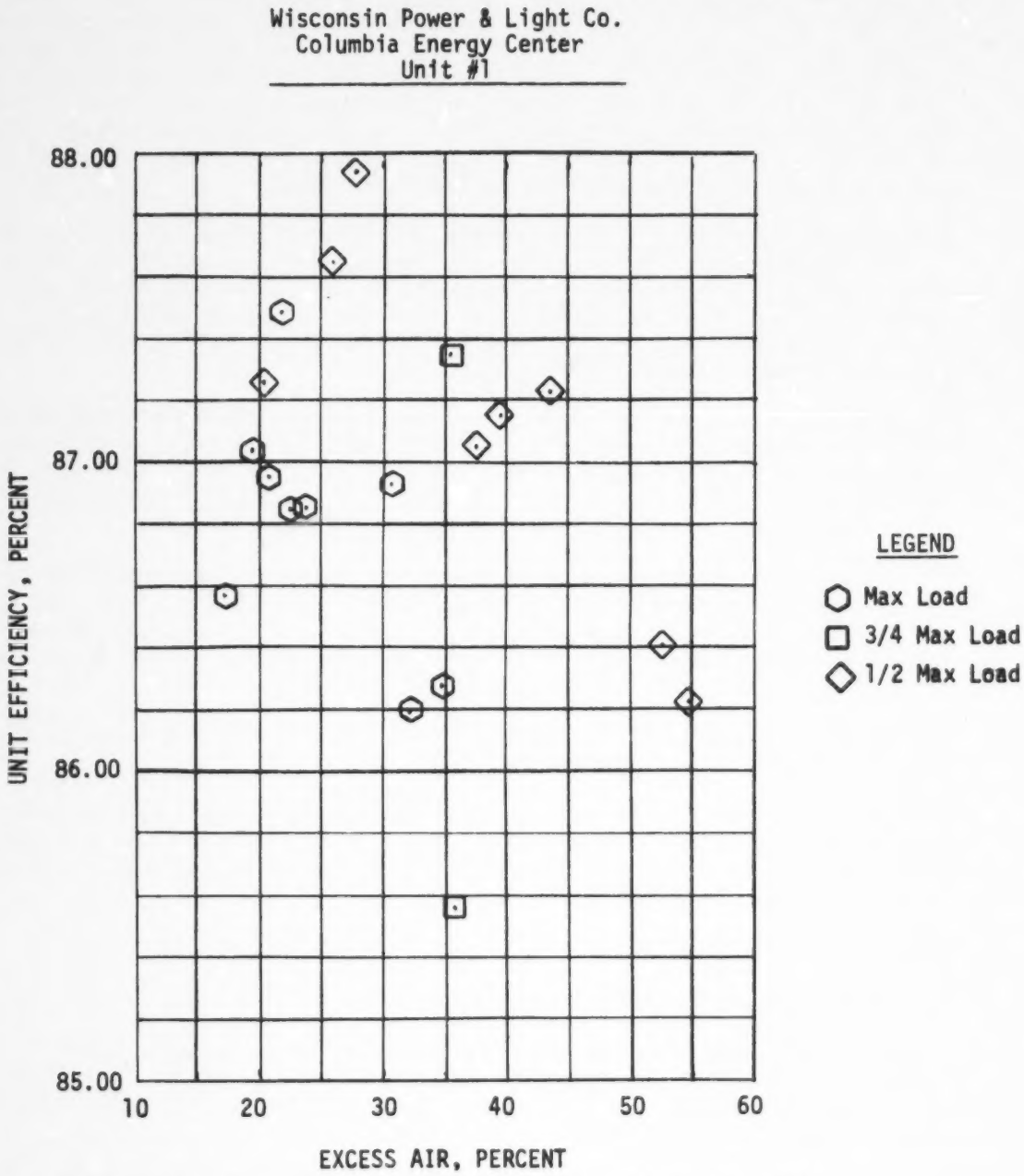

Figure 24: Unit efficiency vs. excess air, baseline study

CO emission levels appear to be affected only by unit load with the levels being higher for full and three-quarter load than for half load. The CO analyzer was inoperative during much of the biased firing testing due to problems with the analyzer source assembly and excessive electrical noise.

No thirty (30) day waterwall corrosion coupon evaluation was performed following the biased firing operation study.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air to Firing Zone-%	Unit Effic. %	Fuel Nozzle Elevation Out of Service
1	426	203.9	NA	20.4	108.2	86.19	Top
2	428	209.1	NA	18.4	116.6	86.54	Top Middle
3	433	249.2	NA	15.2	112.6	85.56	Bottom Center
4	431	250.3	NA	19.0	116.9	86.52	Bottom
5	352	215.9	8.0	26.1	110.0	86.76	Top
6	352	260.2	4.2	21.7	117.5	87.71	Top Center
7	344	227.3	44.8	30.7	125.6	86.30	Bottom
8	263	162.2	1.4	19.7	94.4	87.17	Top & Top Middle
9	258	245.1	1.2	34.2	133.5	87.93	Top Cen. & Bottom Cen.
10	268	266.8	1.6	29.2	128.4	87.37	Bottom & Bottom Mid.
11	417	231.2	NA	23.1	122.7	85.73	Top Middle
12	417	297.2	5.4	24.6	123.4	86.49	Top Center
13	438	280.4	NA	18.4	115.8	86.69	Bottom Center
14	353	222.5	22.6	34.1	117.9	86.92	Top
15	325	231.7	NA	35.8	132.9	86.37	Bottom Center
16	350	246.4	NA	41.3	135.8	86.11	Bottom
17	261	228.7	1.2	35.9	105.8	86.62	Top & Top Middle
18	264	316.9	2.1	36.6	135.8	86.67	Bottom & Bottom Mid.

Analysis of Results

NO_2 emission levels versus theoretical air to the fuel firing zone are plotted on Figure 25. This figure indicates a trend similar to the baseline study tests, with increasing NO_2 levels for increasing TA. No effect due to a variation in unit load is evident in Figure 25. The furnace waterwalls were moderately dirty for most of the biased firing tests and therefore no effect on NO_2 levels due to furnace waterwall deposits was observed.

Figure 26 is a plot of fuel firing elevation out of service versus NO_2 emissions level. The lowest NO_2 emissions levels were obtained with the upper fuel firing elevations removed from service and with the respective compartment dampers 100% open. Overfire air operation is simulated with this method of unit operation. The highest NO_2 levels were obtained when the center fuel firing elevations were removed from service. Removal of the bottom fuel firing elevation from service gives a slight reduction from the higher NO_2 levels obtained with the center levels removed from service.

CO emission level or carbon heat loss versus TA are not plotted. Preliminary plots gave no indication that TA, unit load or furnace wall deposits had any effect on CO emission levels or carbon heat losses.

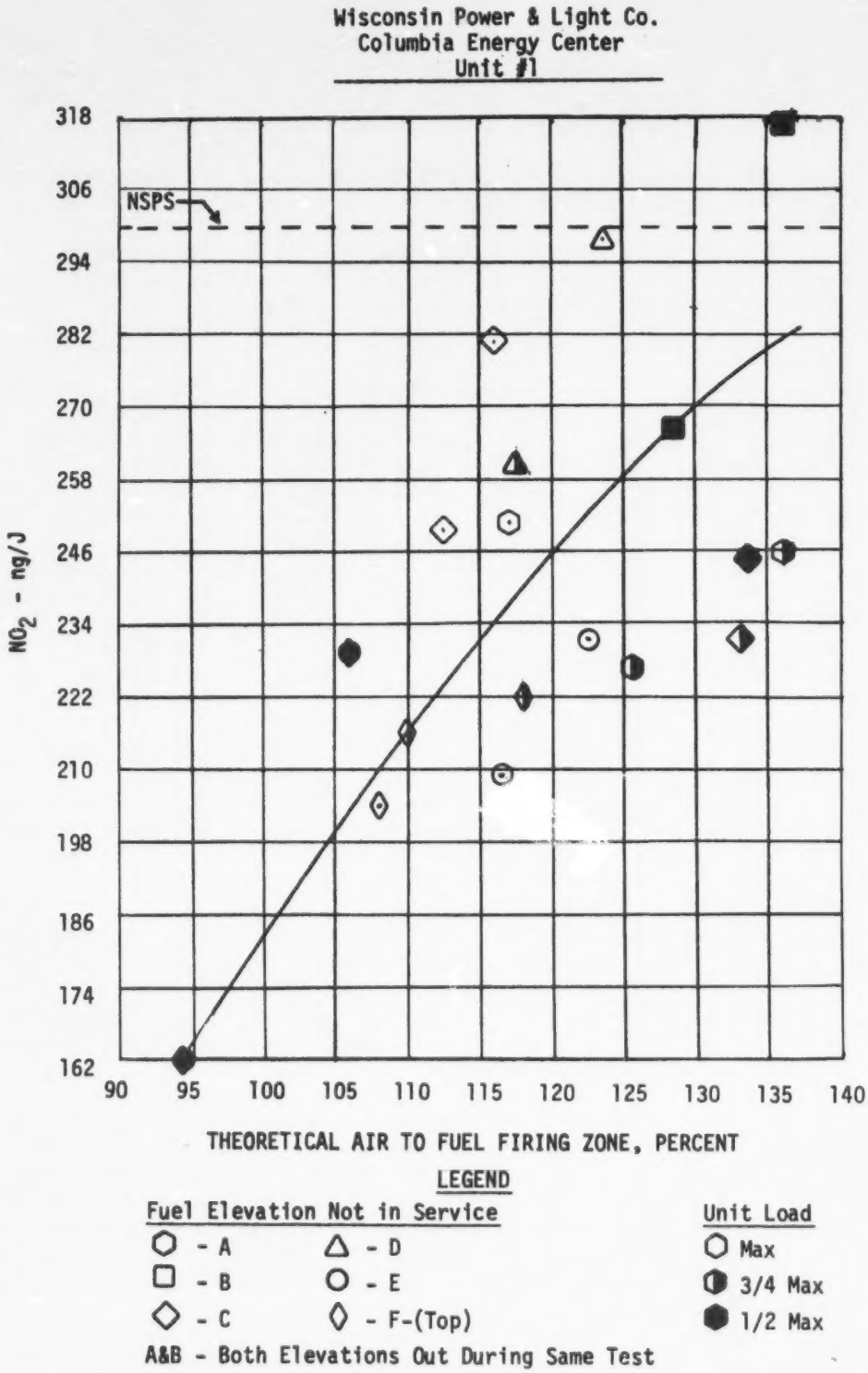

Figure 25: NO_2 vs. TA, biased firing study

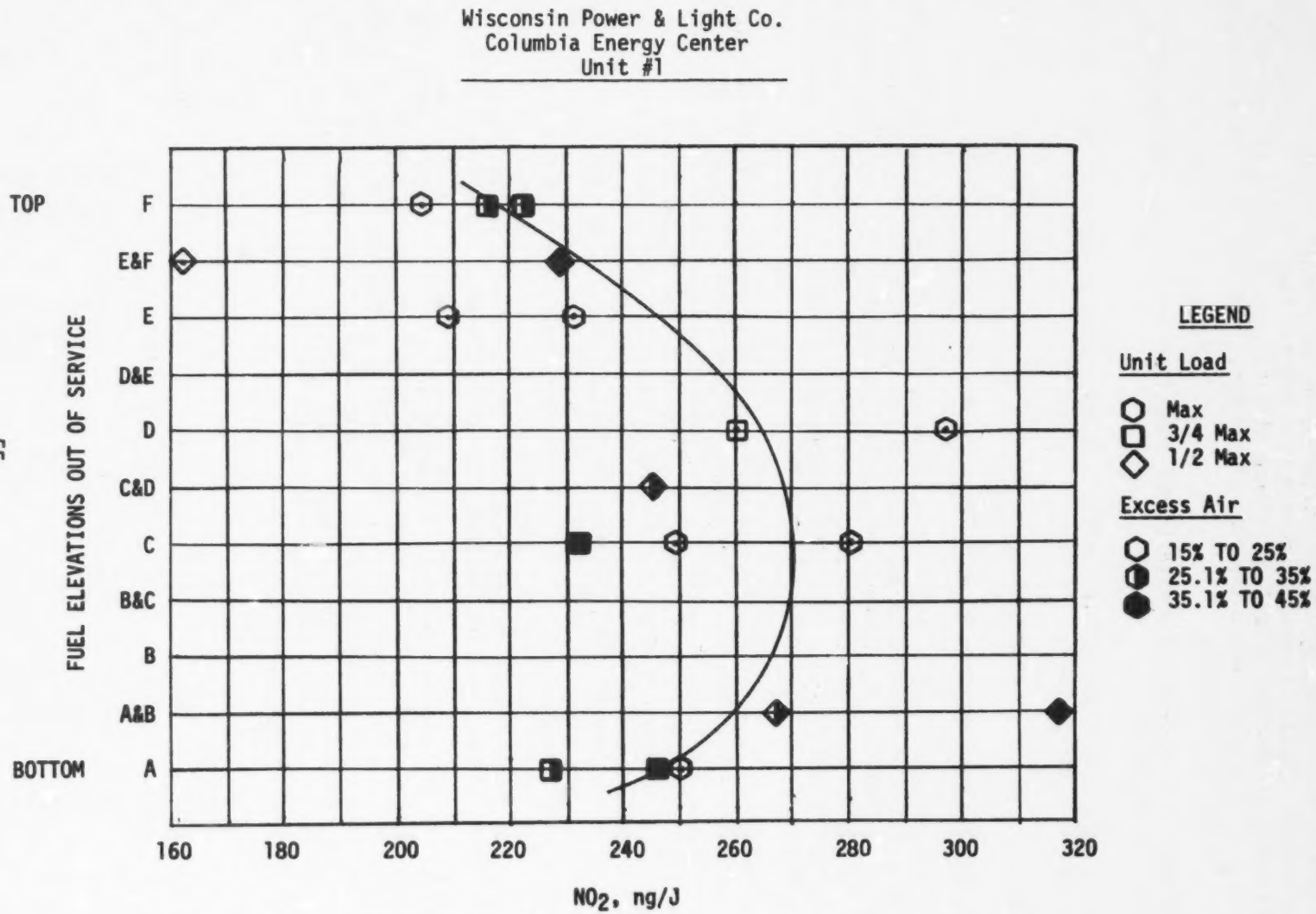

Figure 26: Fuel elevation out of service vs. NO_2, biased firing study

Figure 27 shows steam generator efficiency versus percent excess air at the economizer outlet. Although there is more scatter than in the baseline tests, the trend of decreasing unit efficiency with increasing excess air is still evident. The variation in the fuel elevations firing may have contributed to the scatter in the data.

SO_2 emission levels were monitored for each test and are reported on data sheets A-3 and A-4.

Unburned hydrocarbon emission levels were monitored and were at such low levels as to be unmeasurable.

TASK VI - OVERFIRE AIR OPERATION STUDY

Excess Air and Overfire Air Rate Variation

Tests 1 through 11 were conducted to determine the effect on the NO_2 emission levels and unit performance when varying the overfire air rate with respect to excess air level. For tests 1 through 11, the overfire air registers were held at horizontal tilt while the fuel nozzle tilts were allowed to vary from a -8 degrees to a +8 degrees. The fuel nozzles were allowed to vary to maintain acceptable superheat and reheat temperatures.

The following table shows that NO_2 emission levels increase with increasing theoretical air to the fuel firing zone. Except for tests 1 and 2, NO_2 emission levels are found to correlate well with excess air level. The NO_2 levels for tests 1 and 2 are much higher than expected. No obvious reason for the high NO_2 levels can be found. However one possible explanation is that the furnace wall deposits were considerably different for test 1 and 2. Examination of the waterwall slag patterns for tests 1 and 2 shows that during these tests the slag was 50.8 mm (2 in.) to 101.6 mm (4 in.) thick, glassy and running down the furnace walls. For the remaining tests the slag was about 25.4 mm (1 in.) to 101.6 mm (4 in.) thick and mostly plastic; however, it was not glassy or running down the walls as fast. The problem with the glassy slag is that it reradiates back to the fire increasing the bulk flame temperatures.

Due to the problems encountered with the CO analyzer the CO levels were only monitored for tests 1 and 2. Based on the results of test 1 through 11, the optimum excess air operating level was found to be the minimum, approximately 15 percent at the economizer outlet. The optimum overfire air rate is with the overfire air dampers 100 percent open. This mode of operation will allow 15 to 20 percent of the total combustion air to be introduced above the top level of fuel nozzles depending upon unit load.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	OFA Dampers % Open
1	425	356.1	4.9	23.9	120.9	86.19	0
2	426	354.9	4.9	23.2	115.7	86.54	25
3	439	222.8	NA	21.8	109.7	85.56	50
4	445	203.4	NA	19.7	105.2	86.52	70
5	444	215.4	NA	20.4	104.6	86.76	95

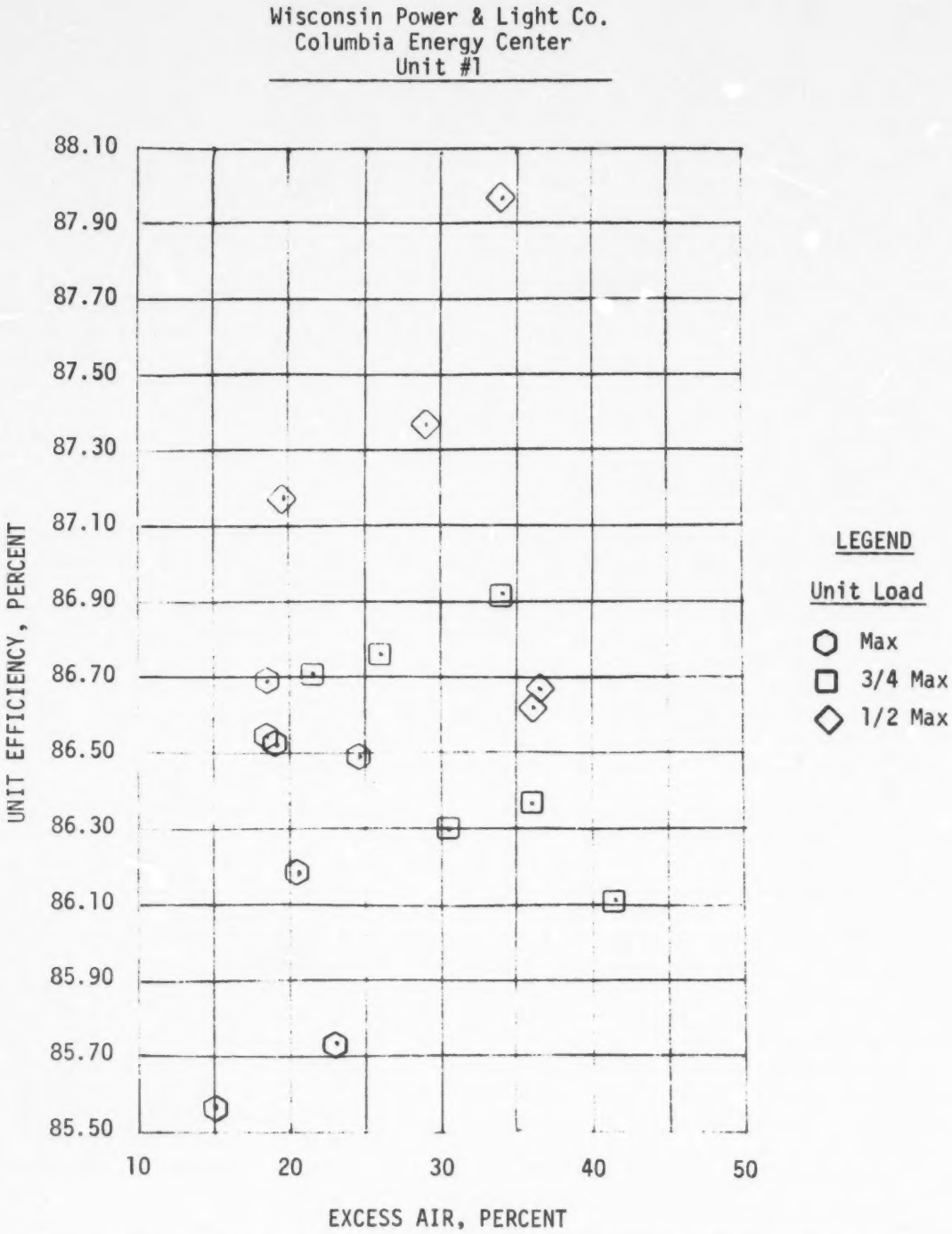

Figure 27: Unit efficiency vs. excess air, biased firing study

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	OFA Dampers % Open
6	446	182.7	NA	13.3	110.7	86.71	0
7	441	177.9	NA	13.9	101.8	86.30	50
8	439	171.4	NA	15.1	99.0	87.17	100
9	398	299.2	NA	36.8	128.2	87.97	25
10	390	274.7	NA	35.8	118.8	87.37	80
11	389	246.5	NA	30.0	111.5	85.73	100

Overfire Air Register Tilt Variation

Seven (7) tests were conducted to determine the effect of fuel nozzle and overfire air register tilt variation on NO_2 emission levels and unit performance. These tests, 12 through 18, were conducted at the optimum overfire air rate (dampers 100 percent open) established in tests 1 through 11. Although tests 1 through 11 indicated an excess air level of approximately 15 percent to be optimum for low NO_x formation, an average excess air level of 24 percent was maintained for tests 12 through 18. The higher excess air level was easier to maintain from the standpoint of boiler operation and did not result in significantly higher NO_2 levels.

The overfire air registers were varied from a -5 degrees to a +30 degrees, while the fuel nozzles were varied from a -5 degrees to a +26 degrees. During a unit outage in early June, 1976 the fuel nozzle tilt mechanism was modified. The bottom two fuel firing elevations were prevented from going below a horizontal tilt, but could travel upward to a maximum +26 degrees. The upper four fuel firing elevations were allowed to travel from a -10 degrees to a +26 degrees. When the bottom two fuel firing elevations were at horizontal, the upper four elevations were at a -10 degrees. As the tilts moved upward, the upper four fuel firing elevations rose farther and faster, so that at the maximum upward tilt all the fuel firing elevations were at a +26 degrees.

For these tests the furnace waterwall slagging conditions ranged from light to moderate waterwall deposits. The slag was in a plastic state in those areas of the waterwalls where the slag was 25.4 mm (1 in.) or thicker and could be seen slowly flowing down the lower waterwalls.

The following table shows that NO_2 emission levels were reduced by movement of the fuel nozzles and overfire air registers away from each other. While tests 16 through 18 have higher NO_2 levels than test 12 through 15 the trends are similar. The differences in the NO_2 levels can be attributed to small variations in boiler operation on a daily basis and to the location of the fuel firing zone in the furnace. For tests 16, 17 and 18 the fuel firing zone was higher in the furnace than tests 12 through 15. With the fuel firing zone higher in the furnace, the waterwall surface area available for cooling of the flame is greatly reduced. The loss of cooling of the flame can result in an increase in flame temperature, which can result in an increase in thermal NO_2 formation.

Parallel operation of the fuel nozzles and overfire air registers is as effective as when they are moved away from each other. Therefore, for ease of testing

and boiler operation, parallel tilt conditions were chosen for the mode of boiler operation in tests 19 through 24.

CO emission levels are not found to be greatly affected by tilt variation. The one test with high CO levels could be the result of the maximum upward fuel nozzle and overfire air register tilts. At these high tilts, the residence time of the hot combustion gases in the furnace would be reduced. This reduction in residence time could affect the oxidation of CO to CO_2.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Fuel Nozzle Tilt Degrees	OFA Register Tilt Degrees
12	446	195.5	4.9	23.9	102.8	87.20	-5	-5
13	444	205.4	1.5	26.9	105.7	86.90	0	-5
14	443	188.5	3.0	26.9	106.0	87.28	-5	0
15	425	198.9	NA	18.3	101.5	86.43	+1	0
16	438	273.7	2.2	24.6	103.9	87.45	+26	0
17	440	224.6	4.5	26.2	104.7	86.88	+2	+30
18	441	223.4	17.0	23.2	103.1	87.13	+26	+30

Load and Furnace Waterwall Deposit Variation at Optimum Conditions

Tests 19 through 24 were conducted at the optimum excess air level, overfire air rate and fuel nozzle and overfire air register tilts determined in tests 1 through 18. These tests were performed to determine the effect on NO_x emission levels and unit performance at the optimized conditions, while varying unit load and furnace wall deposits. The excess air level ranged from a low of 19 percent at full load to a high of 34 percent at half load. The overfire air register dampers were 100 percent open. The fuel nozzles and overfire air registers were essentially parallel for tests 19 through 24. The tilts ranged from horizontal tilt to a +10 degree tilt for the overfire air registers and a +1 to +12 degree tilt for the fuel nozzles.

The following table shows that NO_2 formation is affected by furnace waterwall condition for the three-quarter (3/4) and full load tests. Except for tests 23 and 24, NO_2 emission levels increase with increasing furnace waterwall deposits. NO_2 emission levels are also affected by unit load, with higher NO_2 levels at higher loads.

Except for test 19, CO emission levels are unaffected by unit load or furnace waterwall deposits. The CO levels for test 19 are considerably higher than tests 20 through 24. The higher CO level may be due to the lower excess air level.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Furnace Condition
19	441	182.8	22.1	19.1	99.7	87.66	Moderate
20	438	234.8	1.1	25.4	99.3	86.63	Heavy
21	350	171.8	1.2	30.0	98.6	87.53	Clean

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Furnace Condition
22	342	220.6	1.1	28.5	103.4	87.39	Moderate
23	263	161.9	1.2	32.5	106.1	88.47	Clean
24	259	161.0	1.6	34.2	107.0	87.78	Moderate

Analysis of Results

NO_2, CO and carbon heat loss values versus theoretical air to the fuel firing zone are shown on Figures 28, 29 and 30, respectively. Although only tests 1 through 11 were conducted to determine the effect of TA variation all 24 tests are shown on Figures 28, 29 and 30.

Figure 28 shows that NO_2 emission levels increase with increasing theoretical air to the fuel firing zone. Furnace waterwall deposits and unit load are also indicated on Figure 28. On this boiler, comparison of tests with similar TA's, but different waterwall deposits give no indication that furnace waterwall slagging has any effect on NO_2 emission levels. Two half (1/2) load and two three-quarter (3/4) load tests were performed for the overfire air operation study. The two half (1/2) load tests have the lowest NO_2 emission levels, while the NO_2 emission levels for the three-quarter (3/4) load tests are of the same magnitude as the full load tests.

CO versus theoretical air to the fuel firing zone is plotted in Figure 29. This figure indicates a possible increase in CO levels at theoretical air levels of approximately 100% to 105%. While this is the expected trend, the data plotted in Figure 29 is insufficient to support such a trend. However, carbon heat loss follows a similar trend when plotted versus TA. Figure 30 is a plot of carbon heat loss for the overfire air study. For theoretical air levels in the range from 100% to 110% carbon heat losses are found to rise rapidly. This is also an expected trend and is what previous studies have shown to be true for both carbon heat loss and CO.

The second task in the overfire air study involved the effect of overfire air register tilt variation on NO_2, CO and carbon heat loss. The NO_2 emission levels for these tests are plotted versus the tilt differential between the fuel nozzles and overfire air registers as shown on Figure 31. Preliminary plots of CO and carbon heat loss versus the difference in tilts yeilded no useful information and therefore no plots have been included. The difference in tilts refers to how many degrees toward or away from each other the fuel nozzles and overfire air registers are moved. This difference is calculated by taking the difference in degrees that the overfire air registers are angled toward or away from the fuel nozzles.

Figure 31 indicates that the maximum NO_2 levels are obtained when the fuel nozzles and overfire air registers are angled toward each other. With the exception of one test (#17), minimum NO_2 levels are obtained when the fuel nozzles and overfire air registers are angled away from each other. Most of these tests were performed with clean furnace waterwalls, while test 17 had moderately dirty waterwalls. The NO_2 levels for test 17 were higher than expected. This might be attributed to the heavier waterwall deposits observed for this test.

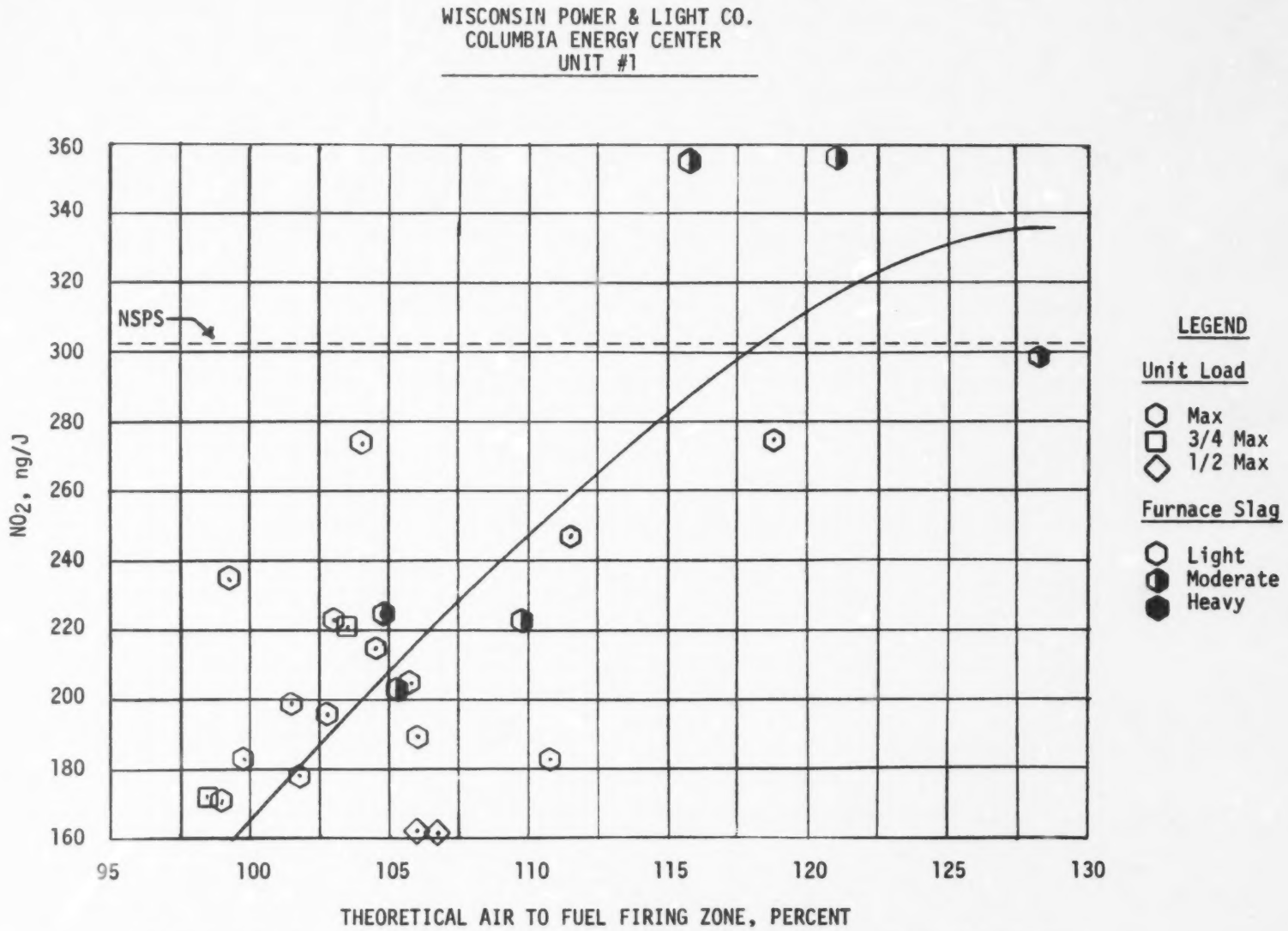

Figure 28: NO_2 vs. theoretical air to fuel firing zone, overfire air study

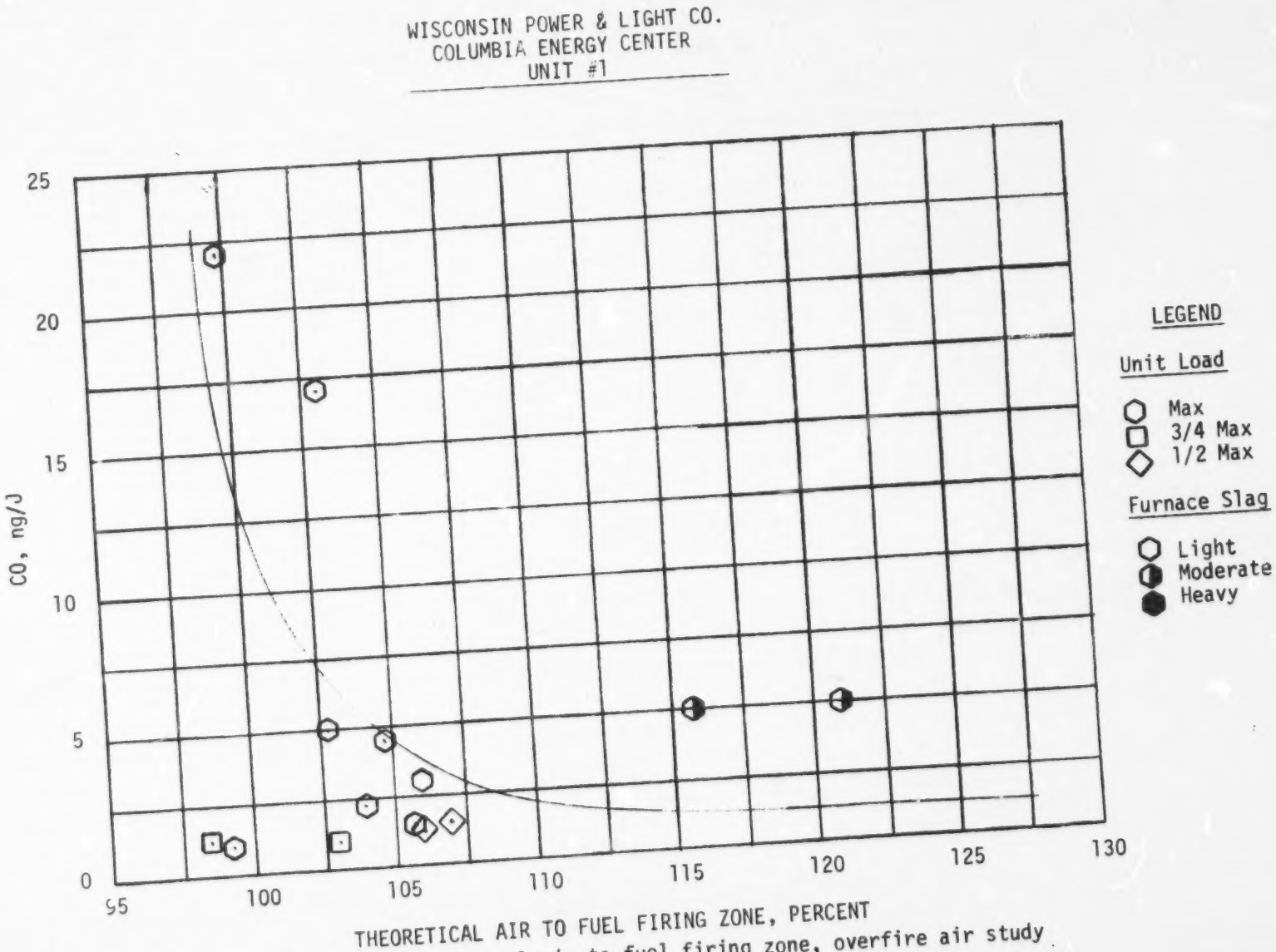

Figure 29: CO vs. theoretical air to fuel firing zone, overfire air study

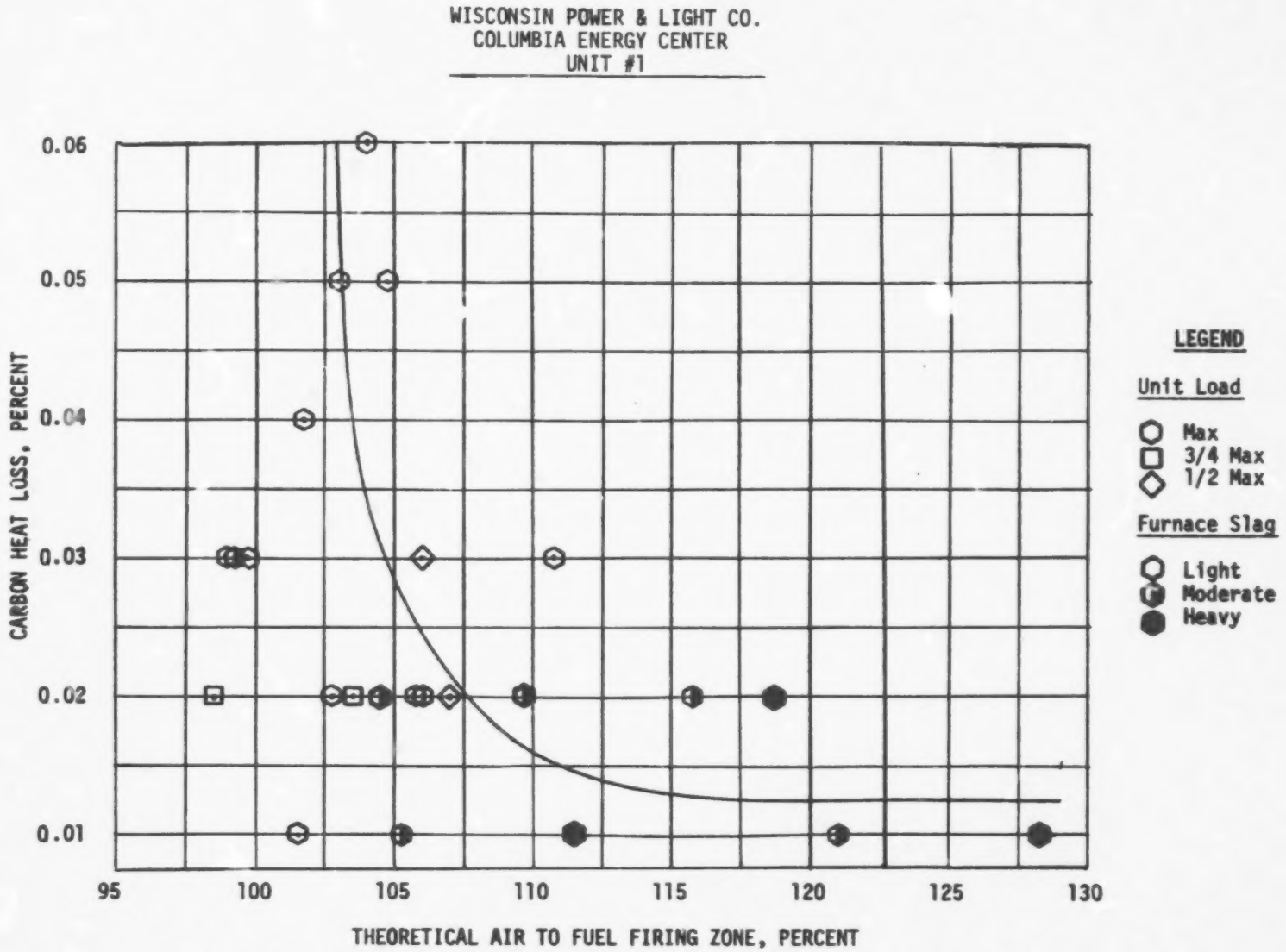

Figure 30: Carbon heat loss vs. theoretical air, overfire air study

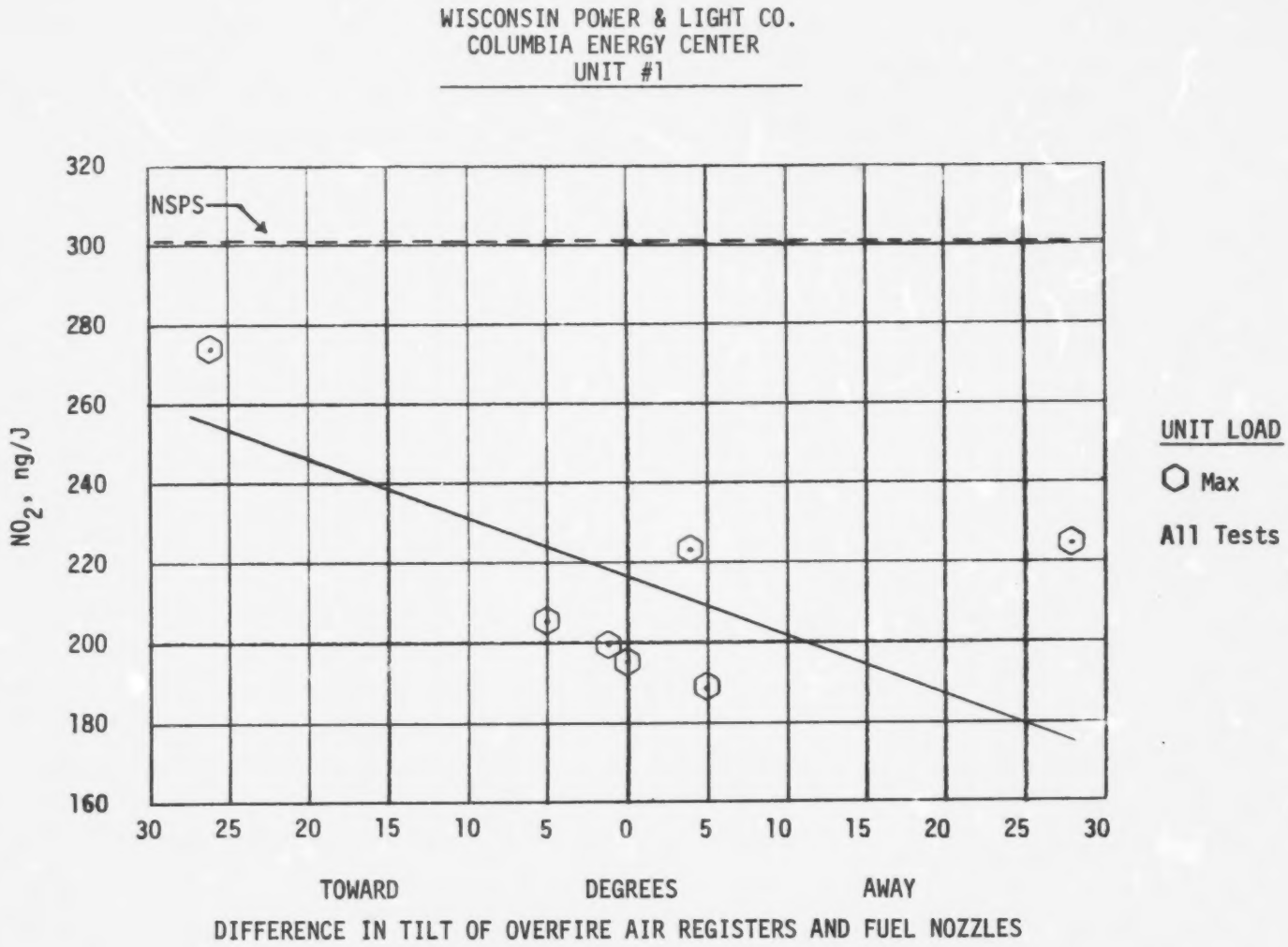

Figure 31: NO_2 vs. difference in tilt, overfire air study

Figure 32 shows unit efficiency versus excess air at the economizer outlet. Examination of only the full load tests shows that a decrease in unit efficiency is evident with increasing excess air at the economizer outlet. Such a trend is in agreement with the baseline tests and with previous studies at Alabama Power Company's, Barry Station, Unit #2 [2].

SO_2 emission levels were monitored for each test and are reported on Sheets A-5 and A-6. No correlation between SO_2 emission levels and excess air level, unit load, or furnace waterwall deposits was apparent.

Unburned hydrocarbons were monitored for all overfire air tests and were at such low levels as to be unmeasurable.

A thirty (30) day waterwall corrosion coupon evaluation was conducted in January and February of 1977. The overfire air register dampers were allowed to modulate between 5% open at half load and 75% to 100% open at full load. Unit loading was varied per Wisconsin Power and Light Company's System demands with full load being maintained as much as possible. The waterwall corrosion study is discussed in the section, "Waterwall Corrosion Coupon Evaluation."

FURNACE PERFORMANCE

Furnace performance at Columbia Energy Center, Unit #1 was monitored by the use of Type "E", chordal thermocouples installed in the furnace waterwalls. A schematic of the thermocouple locations is shown in Figure 33. Furnace performance is measured by furnace waterwall absorption rates. Tabulations of the average waterwall absorption rates, as measured at each chordal thermocouple, are presented in Appendix A on Sheets A22 through A35.

Waterwall temperatures and corresponding absorption rates were found to vary significantly with furnace waterwall deposit conditions. For comparison of the waterwall absorption rates, the full load (MCR) tests for the three different modes of boiler operation are shown on Figures 34, 35 and 36. The average horizontal strip absorption rate profiles of the front and right side walls for these tests are plotted versus the distance above or below the firing zone center.

The baseline test profiles show very little heat absorption variation from the hopper slopes to the furnace outlet. The baseline profiles indicate uniform heavy slagging in the combustion zone which results in slightly depressed rates in that area. The biased firing test profiles also show very little variation over the entire furnace height. The absorption rate profiles for the overfire air tests show little variation from the firing zone center down to the hopper slopes. There is a peaking effect just above the firing zone center and a distinct split in the absorption rate profiles between the upper fuel nozzles and the furnace outlet. This split can be traced to a change in the fuel and auxiliary air damper openings. Those tests conducted in March, 1976 had fuel air damper openings of approximately 30 to 50 percent open and auxiliary air damper openings of approximately 100 percent open. The fuel and auxiliary air damper openings were changed following the testing in March, 1976. Those tests performed in May and June of 1976 had fuel air damper openings of approximately 100 percent open and auxiliary air damper openings ranging from 30 to 50 percent open.

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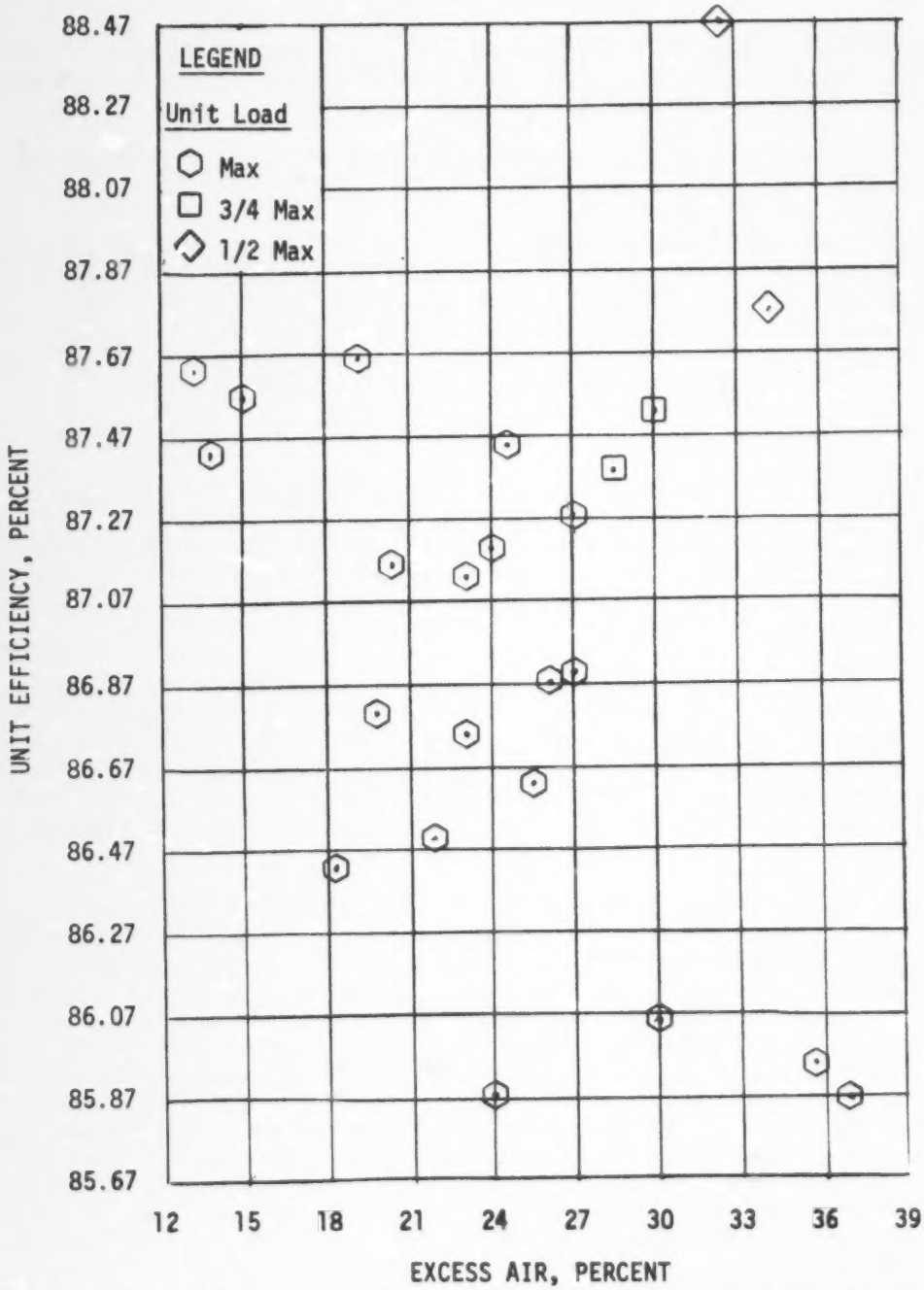
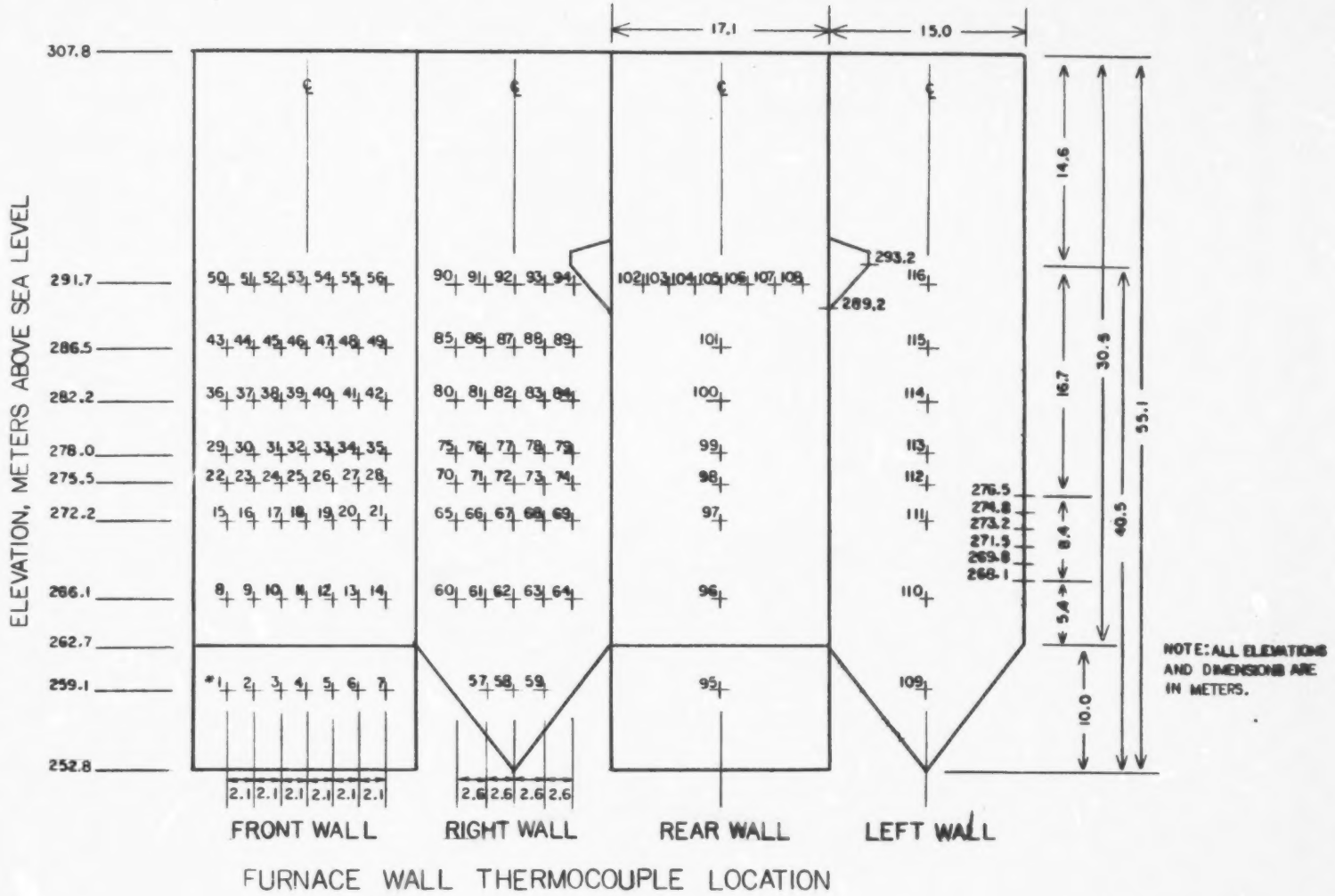


Figure 32: Unit efficiency vs. excess air, overfire air study



FURNACE WALL THERMOCOUPLE LOCATION

FIGURE 33: CHORDAL THERMOCOUPLE LOCATIONS

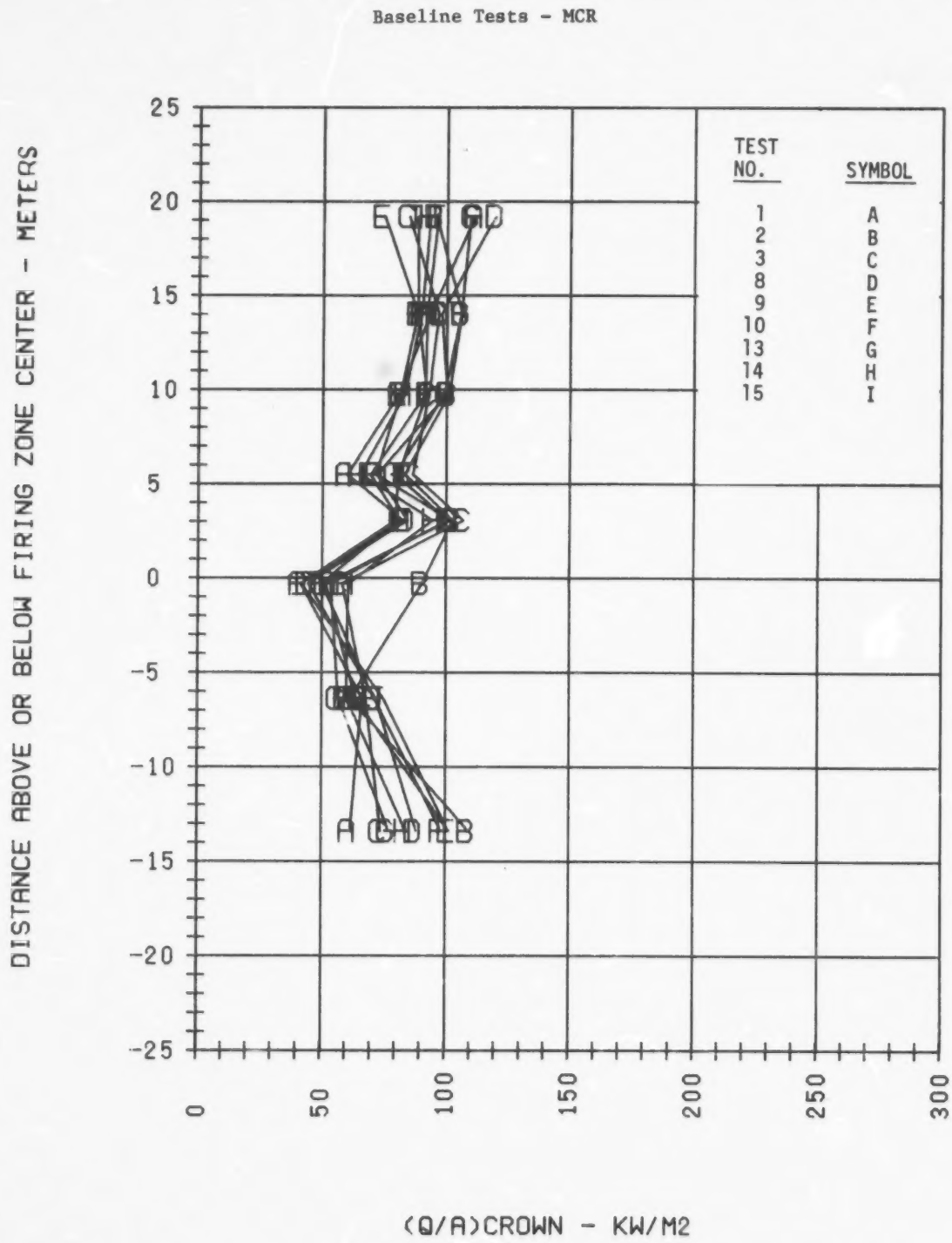


Figure 34: Elevation vs. furnace heat absorption

FURNACE HEAT ABSORPTION RATE PROFILES
HORIZONTAL STRIP RATES

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COLUMBIA #1

Bias Firing Tests - MCR

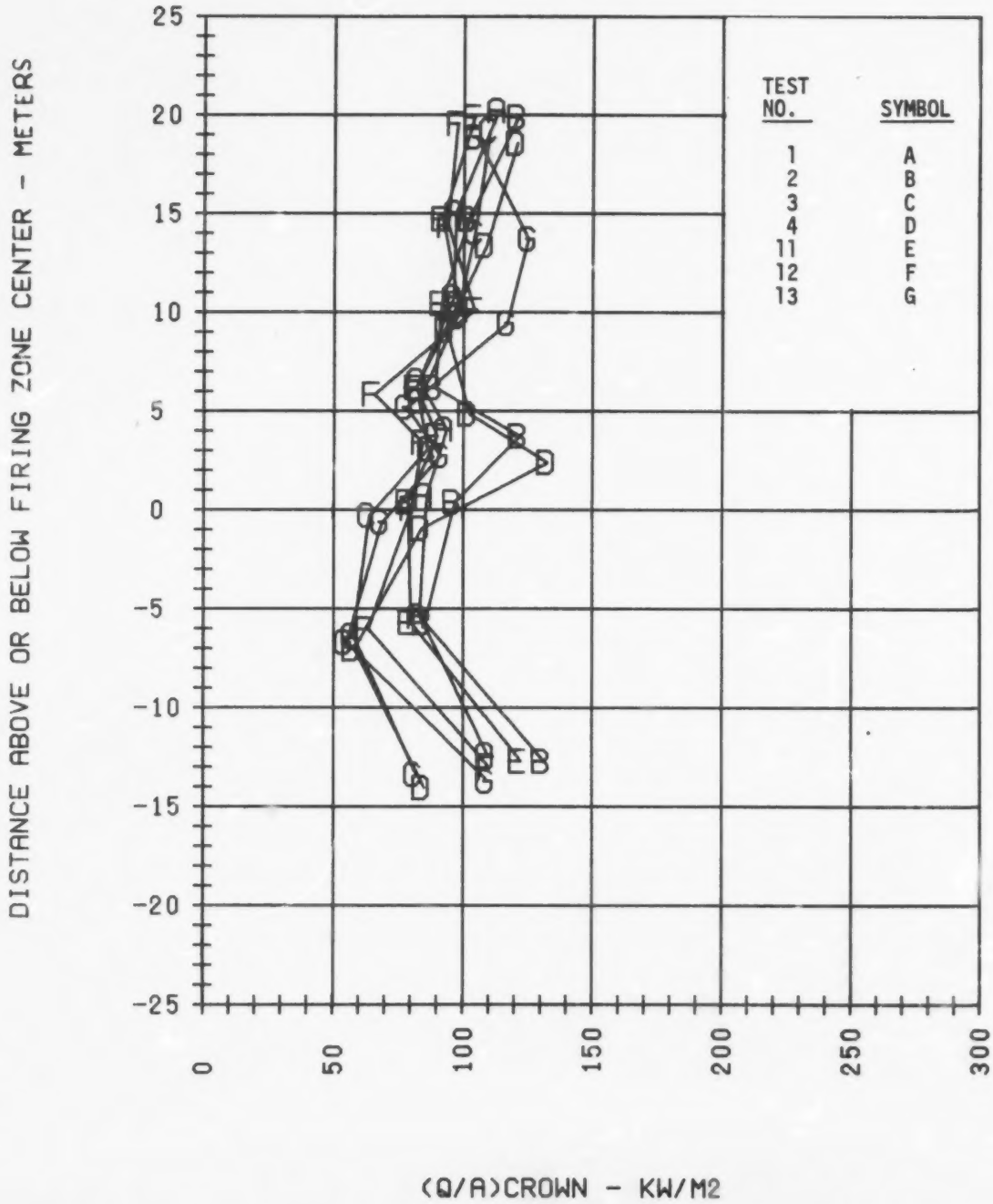

Figure 35: Elevation vs. furnace heat absorption

FURNACE HEAT ABSORPTION RATE PROFILES
HORIZONTAL STRIP RATES

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COLUMBIA #1

Overfire Air Tests - MCR

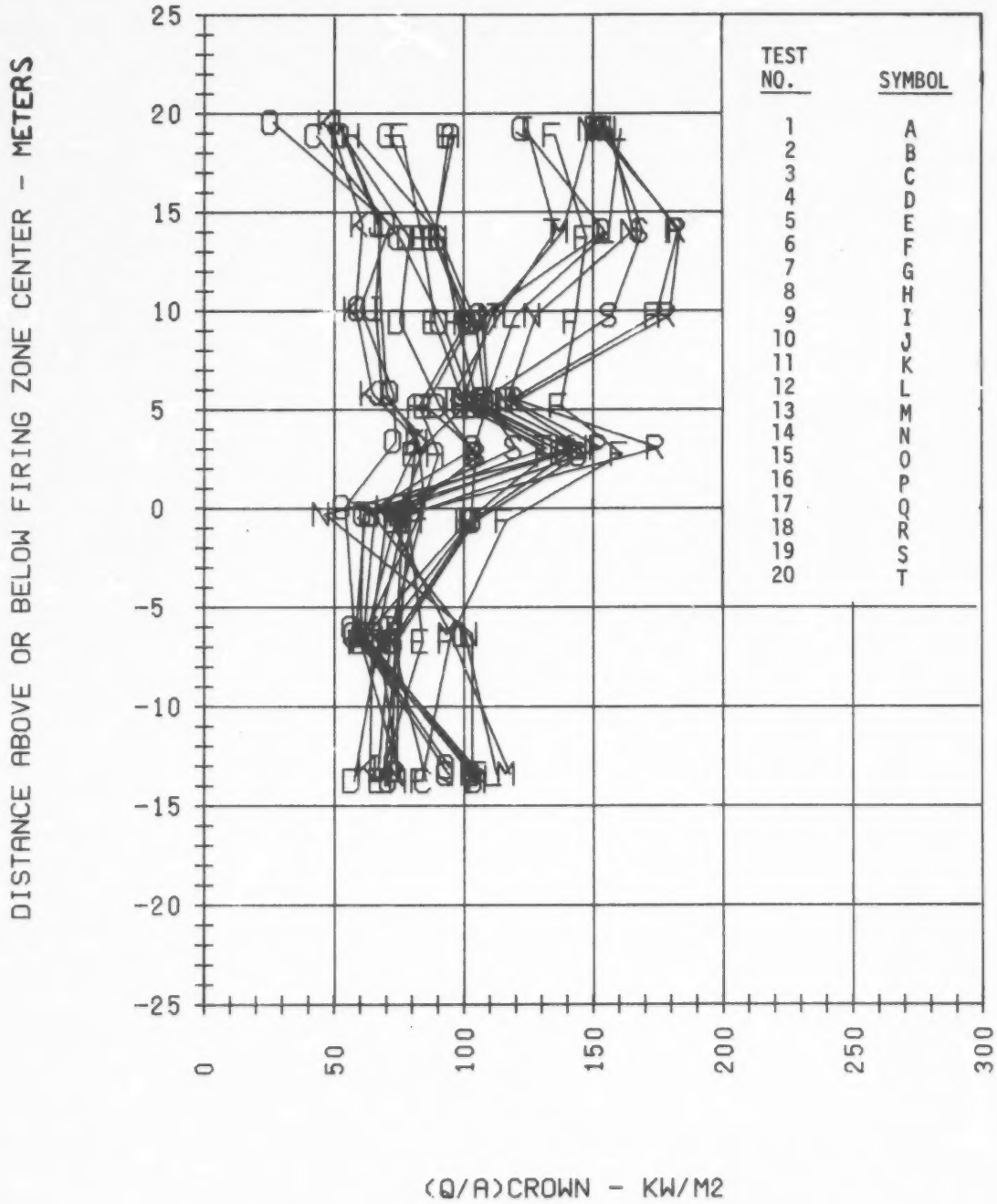


Figure 36: Elevation vs. furnace heat absorption

As mentioned previously, furnace waterwall deposits had a significant effect on waterwall temperatures and corresponding absorption rates. Obtaining the desired slagging conditions proved very difficult and somewhat unpredictable during the testing at Columbia Energy Center, Unit #1. One of the biggest difficulties was in observing the furnace waterwalls to obtain an accurate visual determination of the furnace waterwall deposits.

WATERWALL CORROSION COUPON EVALUATION

Following completion of the steady state phases of the baseline and overfire air test programs, thirty (30) day waterwall corrosion coupon evaluations were performed. The purpose of these evaluations was to determine whether any measurable changes in coupon weight losses could be obtained for the two modes of firing under study.

The individual probes were exposed at five locations on the furnace front wall as shown on Figure 37. The coupon temperatures were maintained at the same levels for each 30 day run and a typical tract of the control temperature range for each of the twenty coupons is shown on Figure 38.

The individual coupon weights were determined before and after each thirty day test and the individual coupon and average probe weight losses are shown on Sheets A57 and A58. The weight losses are calculated as mg/cm^2 of coupon surface area.

Figures 39 and 40 show the unit load schedules for each of the 30 day test periods.

The overfire air portion of the study was conducted as close as possible to the "optimum" operating conditions determined during the overfire air steady state tests.

Throughout the overfire air study the overfire air dampers were maintained at the full open configuration over the range of unit loading shown on Figure 40 with the following exceptions. From January 22 through January 24, January 27 through January 29 and February 8 through February 17 the OFA dampers were opened 75%. Also during a unit start-up on February 25 the dampers were opened from 0 to 20% and then maintained at 40% open during February 26 and February 27.

The percent oxygen was monitored daily during each thirty day study at each probe location and was found to range between 3 and 19 percent O_2 during both the baseline and overfire air studies.

The weight losses calculated for the baseline and overfire air runs were found to be the same with the average weight losses for all five probes as follows:

Baseline	Overfire Air
8.0770 mg/cm^2	8.0933 mg/cm^2

These values are greater than the range of losses experienced at Barry #2, Huntington Canyon #2 and during a control study conducted at C-E's Kreisinger Laboratory by a factor of approximately 2 to 1.

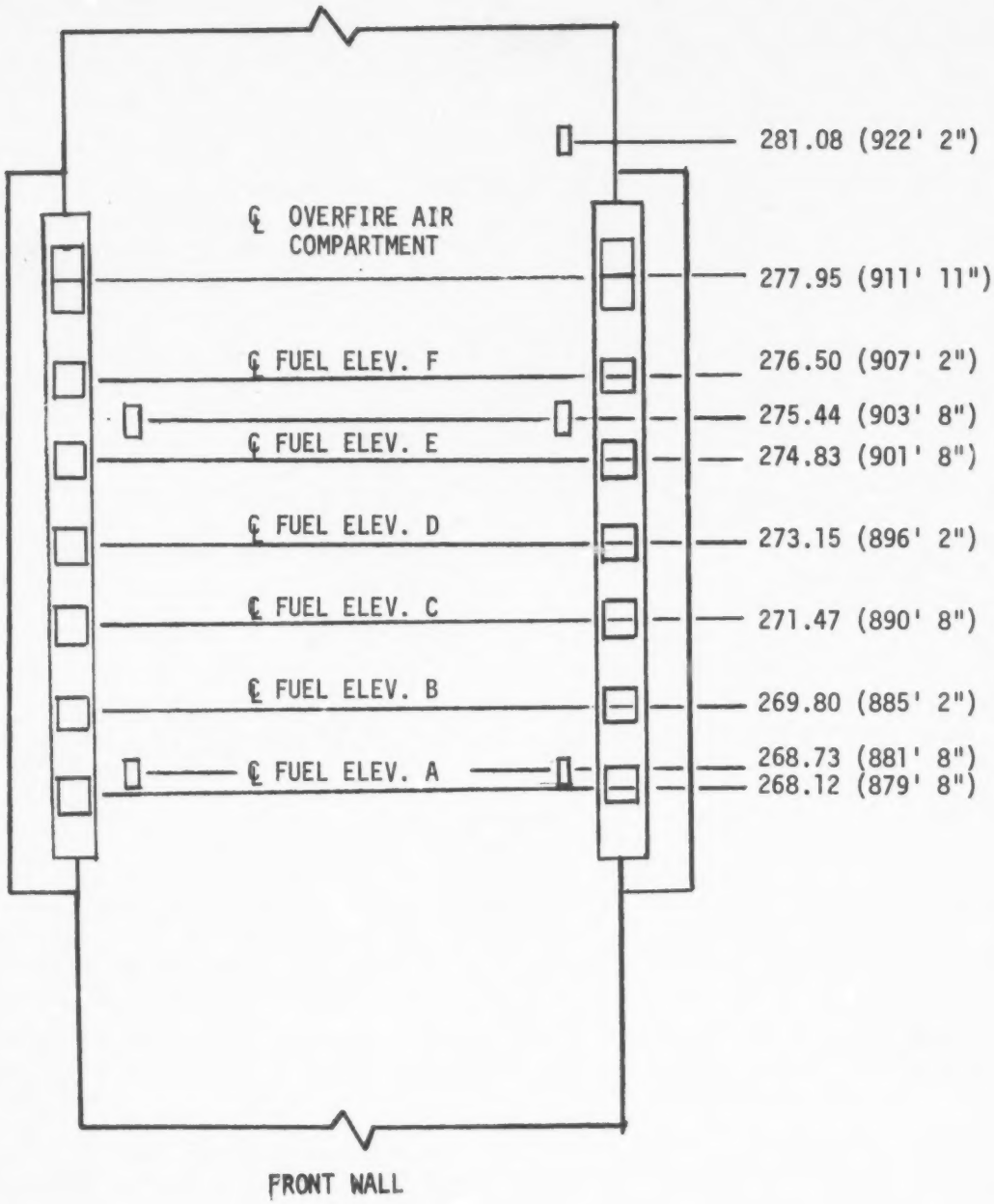


Figure 37. Waterwall corrosion probe locations, Columbia No. 1

Wisconsin Power & Light Co.
Columbia Energy Center
Unit No. 1

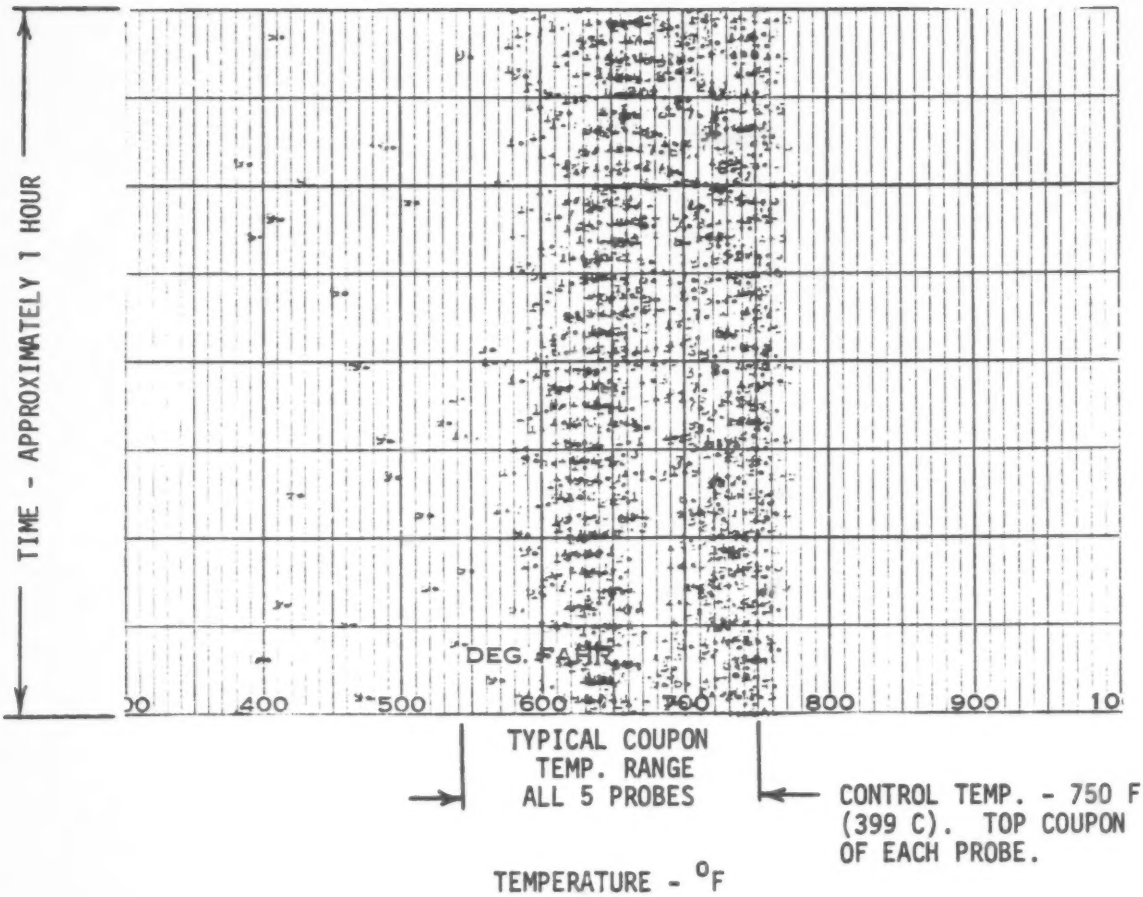
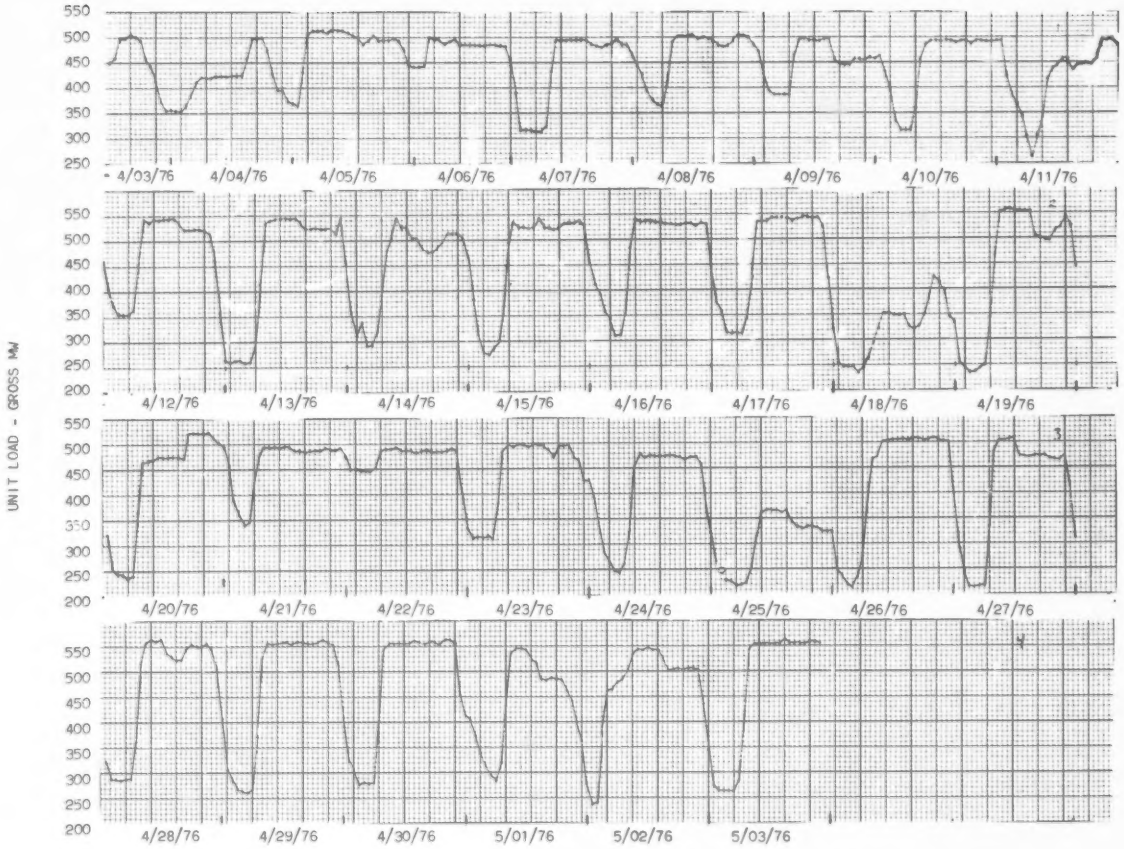


Figure 38. Typical corrosion probe temperature range

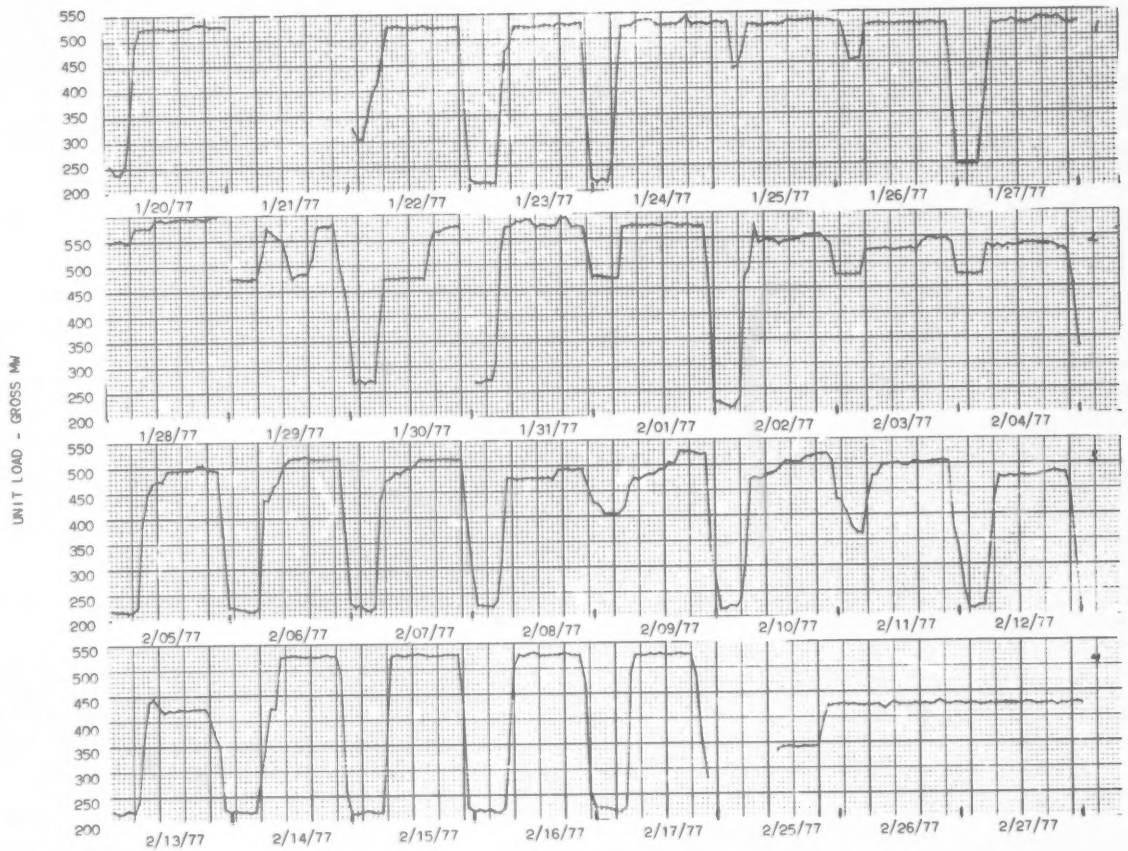
WISCONSIN POWER & LIGHT CO.
COLUMBIA ENERGY CENTER
UNIT #1



AVG. GROSS MW/HR -
30 DAY PERIOD
421.3 MW/HR

FIGURE 39: GROSS MW LOADING VS. TIME - BASELINE CORROSION PROBE STUDY

WISCONSIN POWER & LIGHT CO.
COLUMBIA ENERGY CENTER
UNIT #1



AVG. GROSS MW/HR -
30 DAY PERIOD
442.8 MW/HR

FIGURE 40: GROSS MW LOADING VS. TIME - OVERFIR. AIR CORROSION PROBE STUDY

The results indicate that while there was no change in weight loss between the baseline and overfire air runs something resulted in the losses being consistently higher than expected based on previously obtained data.

Review of test logs reveals a possible explanation. During both runs periodic overheating (up to approximately 540°C) of individual probes occurred due to partial slagging of the probe coupons. This occasionally created a situation where the coupon containing the control thermocouple would be covered with slag while the other coupons of a given probe were still clean. The control thermocouple would then reduce air flow to the entire probe causing the clean coupons to overheat. This situation was corrected when encountered by switching the temperature control to a hotter coupon. The frequency of occurrance was approximately the same for both runs.

Chemical analysis of the coupon deposits also tends to support this observation as the fusibility temperatures of the inner deposits on some of the affected probes were very high. This coupled with the fused state of the initial deposits indicates possible overheating. Coal ash and deposit analysis are shown on Figures 41 and 42.

Wisconsin Power & Light Company
Columbia #1

C-E Power Systems
Field Testing and
Performance Results

WATERWALL CORROSION COUPON DATA SUMMARY

AS FIRED ASH AND COUPON DEPOSIT ANALYSIS

BASELINE STUDY

Sample Location	Pulverized Coal	Probe A Outer	Probe B[1] Initial	Probe C Outer	Probe D Outer	Probe E Outer
Ash Fusibility-°F						
Initial Deformation Temp.	2130	2000	I.S.[2]	2010	2010	1960
Softening Temp.	2170	2080		2080	2080	2010
Fluid Temp.	2290	2270		2270	2310	2140
Ash Composition-%by Weight						
SiO_2	38.6	33.9	9.4	37.7	41.4	28.8
Al_2O_3	17.5	14.4	4.3	14.7	16.4	10.0
Fe_2O_3	6.7	34.8	74.8	29.4	21.5	45.3
CaO	13.5	11.6	3.0	12.4	14.4	9.2
MgO	3.7	3.1	0.7	3.4	3.4	2.1
Na_2O	0.4	0.1	0.1	0.2	0.4	0.3
K_2O	0.5	0.3	<0.1	0.3	0.3	0.4
TiO_2	0.9	0.7	0.3	0.8	0.9	0.5
SO_3	15.2	1.0	4.3	0.9	1.1	1.7
P_2O_5	---	---	0.4	---	---	0.1
Total	97.0	99.9	97.4	99.8	99.8	98.4

1. Outer Sample Not Available
2. I.S. - Insufficient Sample

Figure 41: As-fired ash and coupon deposit analysis, baseline study

WATERWALL CORROSION COUPON DATA SUMMARY

AS FIRED ASH AND COUPON DEPOSIT ANALYSIS

OVERFIRE AIR STUDY

Sample Location	Pulverized Coal	Probe G[1] Initial	Probe H Outer	Probe I Outer	Probe J Outer	Probe K Outer
Ash Fusibility-°F						
Initial Deformation Temp.	2110	I.S.[2]	1920	1930	I.S.[2]	1930
Softening Temp.	2170		1940	1940		1950
Fluid Temp.	2260		2060	2060		2060
Ash Composition-%by Weight						
SiO_2	41.3	6.9	20.7	20.5	12.8	21.5
Al_2O_3	17.2	3.6	8.3	8.1	5.3	7.9
Fe_2O_3	7.6	76.4	56.8	55.8	69.9	57.7
CaO	13.4	3.5	6.9	6.8	4.9	6.8
MgO	4.0	1.0	2.0	1.8	1.3	1.8
Na_2O	0.6	0.5	0.5	0.5	0.4	0.4
K_2O	0.5	0.5	0.5	0.5	0.3	0.4
TiO_2	0.8	0.3	0.5	0.5	0.3	0.4
SO_3	14.0	6.5	3.4	3.7	2.5	2.8
P_2O_5	---	---	---	---	---	---
Total	99.4	99.2	99.6	98.2	97.7	99.7

1. Outer Sample Not Available
2. I.S. - Insufficient Sample

Figure 42: As-fired ash and coupon deposit analysis, overfire air study

HUNTINGTON STATION, UNIT #2

TASKS IV, V & VI - TEST DATA ACQUISITION AND ANALYSIS

Flue gas samples for determination of NO_2, CO, O_2 and THC emission levels were obtained at each of the two economizer outlet ducts. The flue gas samples were drawn from twelve (12) point grids arranged on centroids of equal area in each duct. The SO_2 sample was drawn from a single point in the left economizer outlet duct using a heated sample line. The fly ash sample for carbon loss analysis was obtained from a single point in the left air preheater flue gas outlet duct.

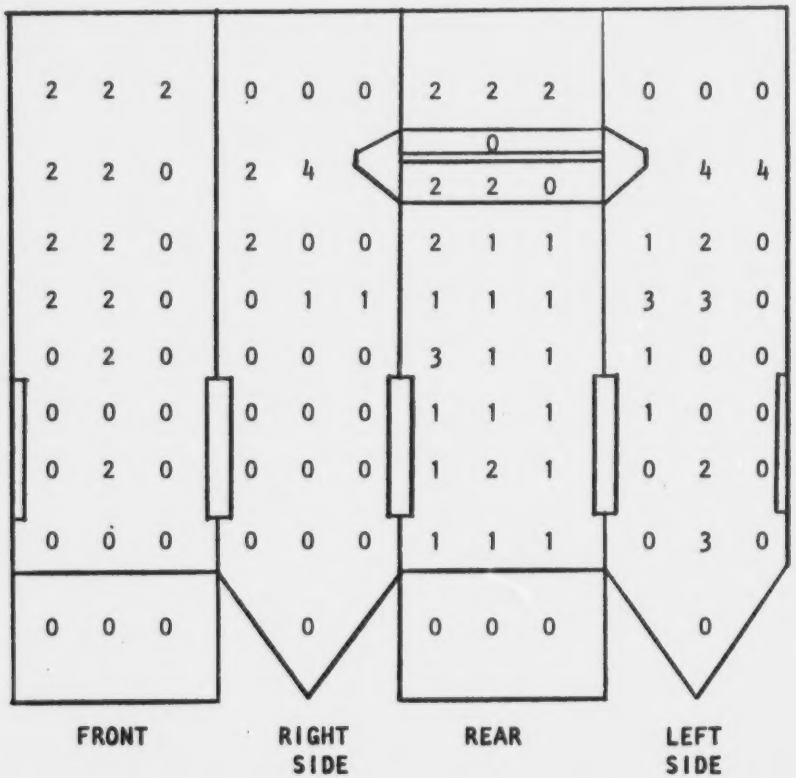
Coal samples were obtained from each feeder and blended to form a composite sample. Each sample was analyzed by the fuels lab at Combustion Engineering Inc.'s Kreisinger Development Laboratory. During some of the testing the Deer Creek Mine Coal was mixed with coal from Peabody Coal Company's Wilberg Mine and from Amercian Coal Company's Church Mine. The Wilberg and Deer Creek Mines were mining the same coal seam but from opposite sides of the mountain. The Church coal was trucked in from a mine 10 to 15 miles south of the plant. Analysis of the Church, Wilberg and Deer Creek coals showed that the coals had very similar characteristics. Although analysis showed the coals to be very similar, visual observations of the furnace waterwalls showed a definite increase in furnace waterwall deposits when firing a blended coal. A blended coal may display properties more unsatisfactory to unit performance than any of the component coals fired separately [8]. Typical slag patterns taken during clean, moderate and heavy slagging conditions at full load operation are shown on Figures 43, 44 and 45. These slag patterns are typical for all modes of boiler operation.

These coals were not blended for those tests conducted in April, May or July of 1975. For those tests conducted in September, October or December of 1975, the coals were usually blended. However, it was impossible to tell on any one day what percent of each coal was being used. The Wilberg and Church Mine coals were always blended with the Deer Creek Mine coal and were never used exclusively.

Summaries of the emissions test data for the baseline, biased firing and overfire air operation studies are tabulated in Appendix B on Sheets B-1 through B-6. Unit performance test data for the three studies are tabulated on Sheets B-7 through B-13. The calculated unit performance test results are tabulated on Sheets B-14 through B-23. Unit efficiency is determined using the Heat Losses Method (ASME Power Test Code, PTC 4.1-1964, Reaffirmed 1973). A set of unit board and computer data was obtained for each test and is tabulated on Sheets B-24 through B-44.

All test data and results are reported in SI Metric Units with the exception of the board and computer data, which are reported in the engineering units provided by plant instrumentation.

FURNACE WATERWALL DEPOSIT PATTERN



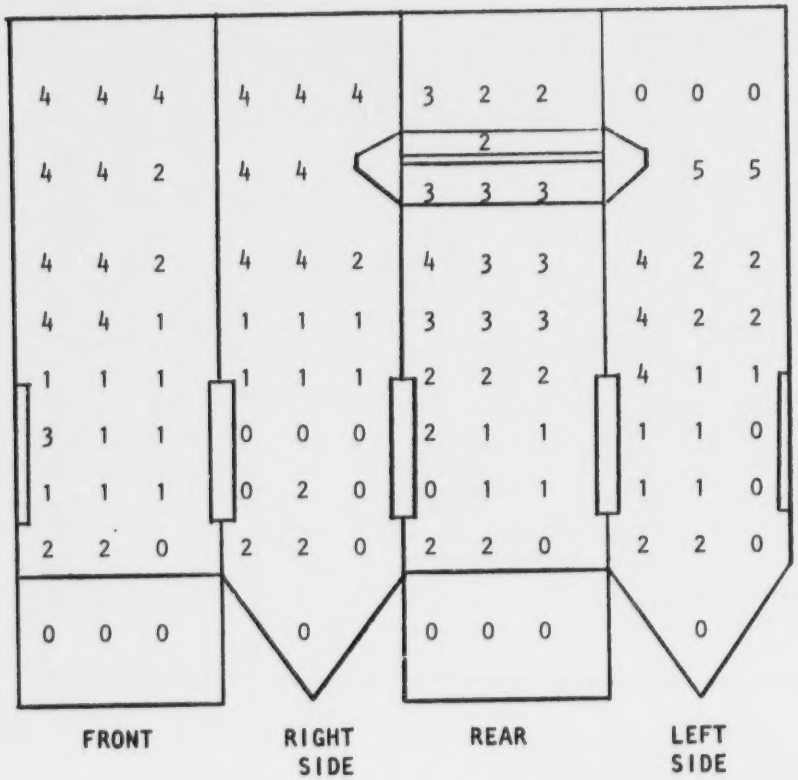
KEY

NO ASH	0
FUZZY <13 MM	1
LIGHT 13 MM - 25 MM	2
LIGHT TO MED. 25 MM - 50 MM	3
MED. TO HEAVY 50 MM - 100 MM	4
HEAVY >100 MM	5
RUNNING SLAG	6

NOTE: 25.4 MM = 1 INCH

Figure 43: Furnace waterwall deposit pattern, clean furnace

FURNACE WATERWALL DEPOSIT PATTERN



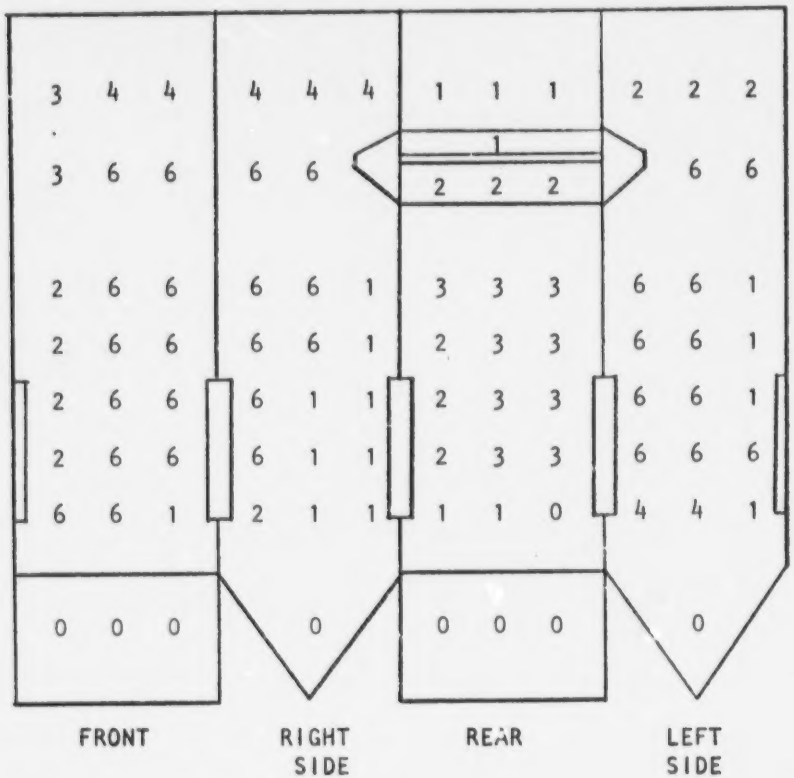
KEY

NO ASH	0
FUZZY <13 MM	1
LIGHT 13 MM - 25 MM	2
LIGHT TO MED. 25 MM - 50 MM	3
MED. TO HEAVY 50 MM - 100 MM	4
HEAVY >100 MM	5
RUNNING SLAG	6

NOTE: 25.4 MM = 1 INCH

Figure 44: Furnace waterwall deposit pattern, moderate slag furnace

FURNACE WATERWALL DEPOSIT PATTERN



KEY

NO ASH	0
FUZZY <13 MM	1
LIGHT 13 MM - 25 MM	2
LIGHT TO MED. 25 MM - 50 MM	3
MED. TO HEAVY 50 MM - 100 MM	4
HEAVY >100 MM	5
RUNNING SLAG	6

NOTE: 25.4 MM = 1 INCH

Figure 45: Furnace waterwall deposit pattern, heavy slag furnace

The thirty (30) day waterwall corrosion coupon evaluations were conducted using a specially designed probe consisting of four individual coupons. The waterwall corrosion coupon evaluations are described and discussed under a separate subsection in this report.

TASK IV - BASELINE OPERATION STUDY

Load and Excess Air Variation - Clean Furnace

Tests 1 through 7 were conducted to determine the effect of varying excess air on unit emission levels and performance. These tests were conducted at three unit loads with clean furnace conditions. Maximum and minimum excess air levels of 40 percent and 15 percent respectively were considered by Utah Power and Light Co. as acceptable modes of unit operation at full load. These limits were exceeded on a few occasions.

As shown in the following table, NO_2 emission levels increased with increased excess air. At equivalent levels of theoretical air to the fuel firing zone (TA), NO_2 emission levels were higher at full load than at half load.

CO emission levels did not change appreciably with changes in excess air level or unit loading. The effect of excess air level and unit loading on unit efficiency, carbon heat loss and unburned hydrocarbon and sulfur dioxide emission levels is discussed in conjunction with the other baseline tests.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Furnace Condition
1	376	248.0	NA*	18.9	116.4	98.92	Clean
2	380	262.8	6.9	27.4	124.8	90.37	Clean
2A	377	332.4	7.7	32.9	130.1	90.16	Clean
3	380	357.0	8.2	40.9	137.8	89.56	Clean
4	298	328.0	NA	28.9	126.9	90.05	Clean
5	204	249.2	4.8	23.7	122.9	91.05	Clean
6	203	284.3	4.8	32.1	131.1	91.05	Clean
7	202	360.3	5.0	50.0	150.0	90.51	Clean

Load and Excess Air Variation - Moderately Dirty Furnace

Tests 8 through 12 were to have been conducted with a moderately slagged furnace. However, when operating with the Deer Creek Mine Coal, it was difficult to obtain any appreciable amounts of slag on the furnace waterwalls. As a result of this, tests 8 through 12 were actually conducted with clean furnace waterwalls. Excess air levels and unit load were allowed to vary per the test program.

The NO_2 levels for Tests 8 through 12, as shown in the following table, are also found to be proportional to the excess air levels. Although tests 8 through 12 were conducted with excess air levels, unit loads and furnace wall deposits similar to tests 1 through 7, the NO_2 emission levels are generally lower. One

* NA - CO values not available due to operational difficulties with CO analyzer.

possible explanation for this difference in NO_2 emission levels for similar tests is the effect of fuel nozzle tilt. The fuel nozzles had a higher upward tilt for tests 1 through 7. While the higher tilts reduce the residence time of the hot gases in the furnace, they also decrease the furnace waterwall surface available for cooling. The decrease in surface cooling area results in a higher flame temperature, which can cause higher NO_2 emission levels. The only exception to this is Test #8 which correlates well with Test #1. As in Tests 1 through 7, at similar theoretical air levels to the fuel firing zone, NO_2 emission levels are again higher for full load tests than half load tests.

CO emission levels again did not show any appreciable change with changes in excess air level or unit loading. The only exception to this is Test #9 which when compared to a similar test (#2 or 2A) has an unusually high CO level for the excess air level at which the unit was operating.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Furnace Condition
8	378	267.1	6.9	19.5	117.5	89.93	Clean
9	377	258.6	37.5	29.0	126.3	90.10	Clean
10	375	295.3	NA	40.9	137.8	89.64	Clean
11	203	232.6	4.6	27.4	126.4	91.07	Clean
12	208	318.8	5.0	48.8	147.6	90.75	Clean

Load and Excess Air Variation - Dirty Furnace

The test program called for Tests 13 through 19 to be conducted with heavy furnace wall deposits. As in Tests 8 through 12 it was difficult to obtain any appreciable amount of slag on the furnace waterwalls. However, moderately thick furnace wall deposits of 12.7 mm (1/2") to 50.8 mm (2") were obtained. Excess air and unit load were again varied per the test program.

As shown in the following table increasing NO_2 emission levels are again found with increasing excess air levels. Again, for similar TA's, NO_2 emission levels for full load are higher than NO_2 levels at half load. There is no other obvious correlation between NO_2 emission level and unit loading.

Excess air variation and unit load again showed no obvious effect on CO emission levels.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Furnace Condition
13	377	213.8	10.4	15.0	113.1	90.38	Moderate
14	375	253.7	7.2	20.2	118.1	90.34	Moderate
15	375	319.1	8.3	35.5	132.6	90.30	Moderate
16	298	285.2	4.1	23.0	121.3	90.78	Moderate
17	204	215.7	4.5	25.2	124.3	90.74	Moderate
18	206	233.0	NA	28.9	127.9	90.43	Moderate
19	205	333.1	5.0	47.8	146.6	90.34	Moderate

Analysis of Results

The changes in NO_2, CO and carbon heat loss versus TA are shown on Figures 46, 47 and 48, respectively. For the baseline operation study the TA is essentially the same as the total air.

Figure 46 shows that NO_2 emission levels correlate reasonably well with theoretical air to the fuel firing zone. Increasing TA results in increased NO_2 emission levels. This correlation is in agreement with previous studies which have shown that NO_2 emission levels are proportional to the concentration of oxygen available for combustion.

Based on the data as plotted in Figure 46, it can be concluded that there is some variation of NO_2 emission levels with unit load. As discussed previously for similar theoretical air levels to the fuel firing zone, NO_2 emission levels for full load unit operation are higher than NO_2 levels at half load unit operation. NO_2 emission levels for three-quarter (3/4) load operation are of the same order of magnitude as full load NO_2 levels.

There is no distinct variation of NO_2 emission levels with furnace waterwall deposits. The results of those tests performed with moderately dirty furnace wall deposits have too much scatter to show any correlation between NO_2 levels and furnace wall deposits. This lack of correlation may be partially attributed to the fact that visual observations of furnace waterwall deposits is very subjective. While furnace wall deposits for Tests 13 through 19 were considered to be moderately dirty, they may have in fact been very similar to furnace waterwall conditions for Tests 1 through 12.

With the exception of Test #9, Figure 47 shows that CO emission levels did not show any appreciable variation with changes in TA. As mentioned previously Test #9 had an unusually high CO level when considering the furnace slag conditions and the excess air level at which the unit was operating. Below 120 percent TA, Figure 47 shows a slight rise in CO emission levels. This rise in CO levels below 120 percent TA is in agreement with baseline studies at Alabama Power Company's, Barry Station, Unit #2. However, the data as presented in Figure 47 is insufficient to be considered a trend for this study.

Unit loading had no significant effect on CO emission levels. CO emission levels for the half load and three-quarter load tests are lower than the CO levels for full load tests. However, as the CO levels for all the unit loads are of the same order of magnitude, it is difficult to distinguish what effects changes in unit loading have on CO levels. Any distinction is further hampered by the fact that the half load tests are performed at higher excess air levels than full or three-quarter load tests. The higher excess air level operation at lower loads would promote more complete combustion resulting in lower CO levels. Boilers are operated at higher excess air levels at half load for temperature control purposes, i.e., to maintain superheat and reheat outlet temperatures and therefore the maximum and minimum excess air limits were shifted upward for half load operation. Furnace waterwall slag conditions are found to have no effect on CO emission levels.

Figure 48 shows percent carbon loss in the fly ash versus percent theoretical air to the fuel firing zone. The carbon heat loss results are very similar to the CO results. There is a general trend of increasing carbon heat loss with

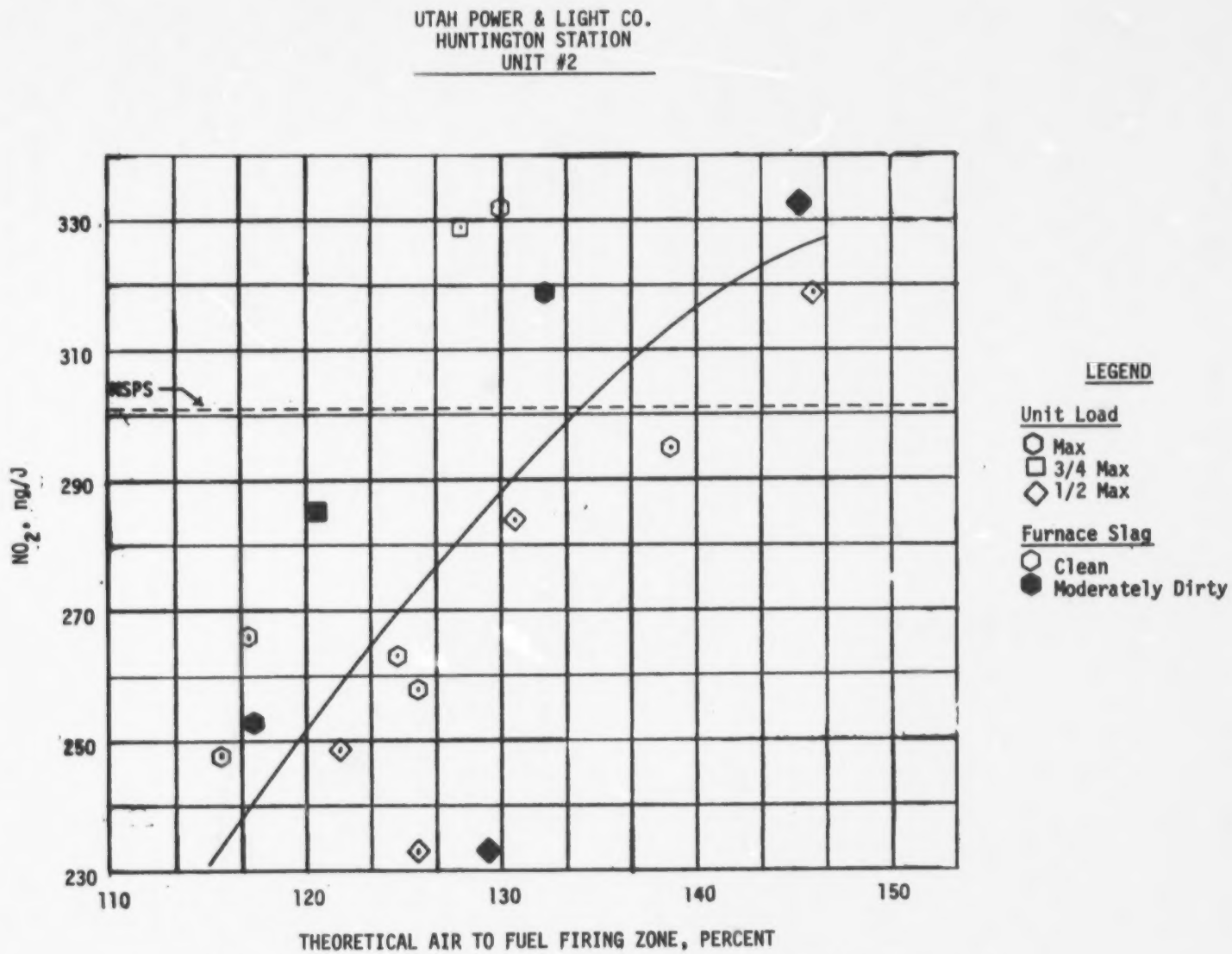


Figure 46: NO_2 vs. theoretical air to fuel firing zone, baseline study

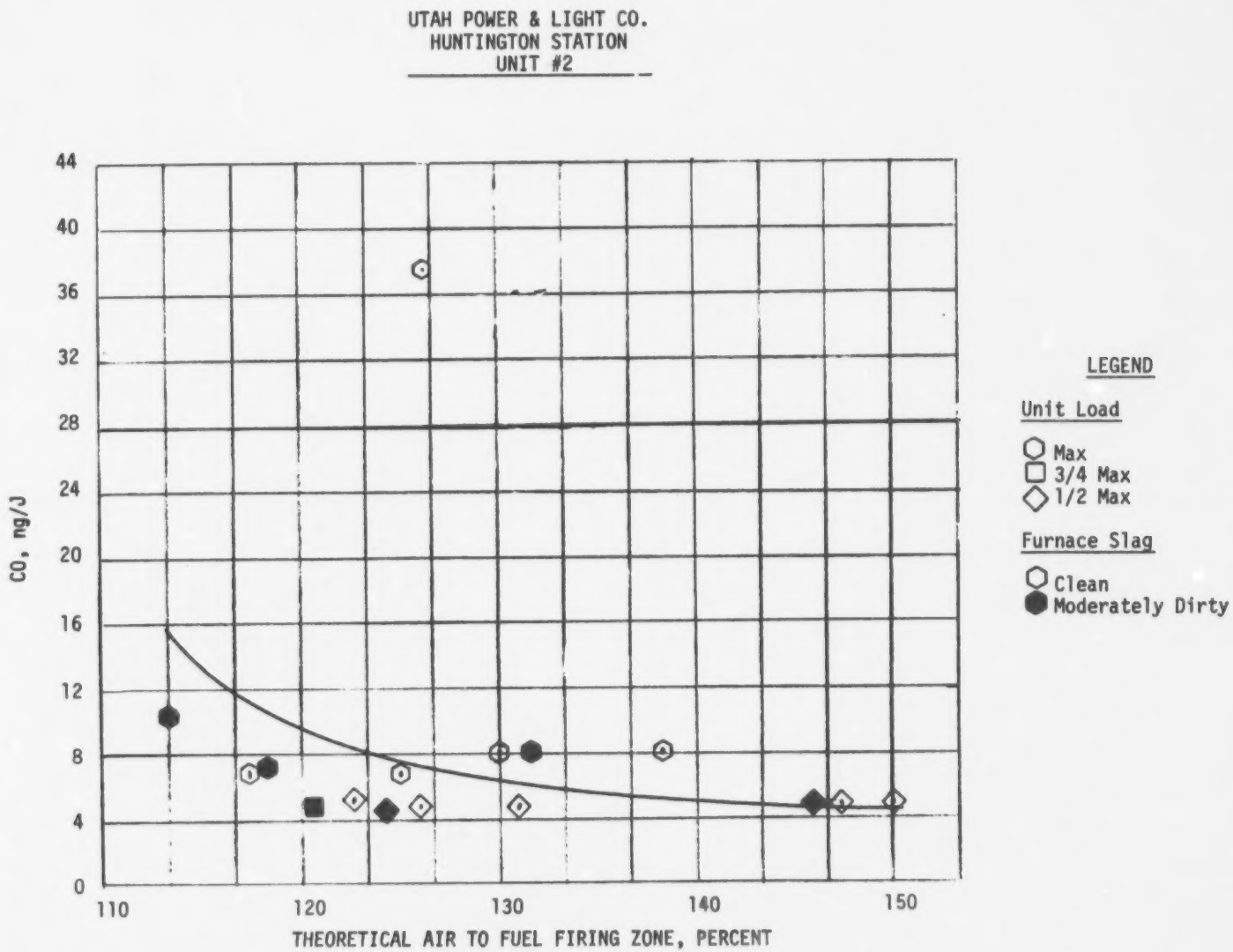


Figure 47: CO vs. theoretical air to fuel firing zone, baseline study

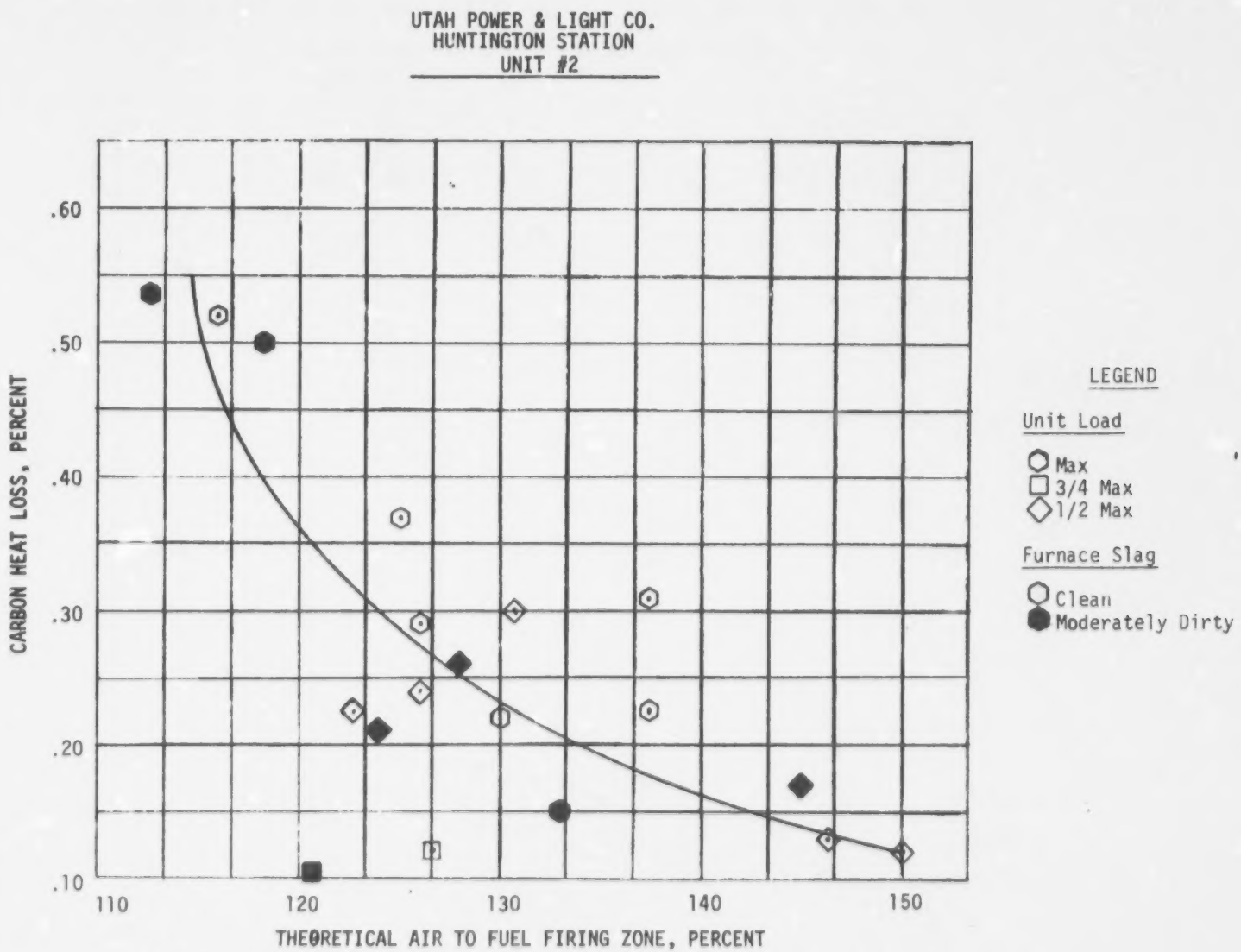


Figure 48: Carbon heat loss vs. theoretical air, baseline study

decreasing TA. No distinct variation of carbon heat loss with unit loading is evident with the exception that carbon heat losses for the half load tests are lower than the carbon heat losses for full load tests. As with the CO results, this variation may be related to the fact that the half load tests were run with higher excess air levels than full load tests. The higher excess air levels would promote better carbon burnout. Based on the data as plotted in Figure 48, carbon heat losses appear to be unaffected by variations in furnace waterwall deposits.

Figure 49 shows unit efficiency versus percent excess air at the economizer outlet. When viewed without regard to unit load, the scatter in the data as plotted in Figure 49 overshadows any obvious trend. However, when full load and half load tests are examined separately a decrease in unit efficiency is found with increasing excess air at the economizer outlet.

No effect on unit efficiency was obvious for changes in furnace waterwall deposits for the baseline operation tests.

SO_2 emission levels were monitored for each test and are reported on Sheets B-1 and B-2. No correlation was evident between SO_2 emission levels and excess air, unit loading or furnace waterwall deposits. It was not possible to control the SO_2 emission level as it is more a function of the sulfur content of the fuel rather than the mode of boiler operation.

Unburned hydrocarbon emission levels were monitored and were found to be at such low levels as to be unmeasurable.

A thirty (30) day waterwall corrosion coupon test was conducted in April and May of 1975. The boiler was operated normally with full load being maintained as much as possible. The waterwall corrosion coupon test is discussed in the section "Waterwall Corrosion Coupon Evaluation."

TASK V - BIASED FIRING OPERATION STUDY

Fuel Elevations Out of Service Variation

Tests 1 through 16 were conducted to determine the effect on NO_2 emission levels, when taking various fuel elevations out of service (biased firing) at three different unit loadings and two excess air levels. The test program called for half load tests being performed with two adjacent fuel firing elevations out of service. However, Utah Power and Light Co. would not permit this mode of operation. As a result, the half load tests were performed with only the top fuel firing elevation of the two adjacent elevations out of service.

As can be seen in the following table, maximum NO_2 emissions control was obtained with the top elevation of fuel nozzles out of service (Tests 1, 4, 7, 9 and 12).

No thirty (30) day waterwall corrosion coupon evaluation was performed following the biased firing operation study.

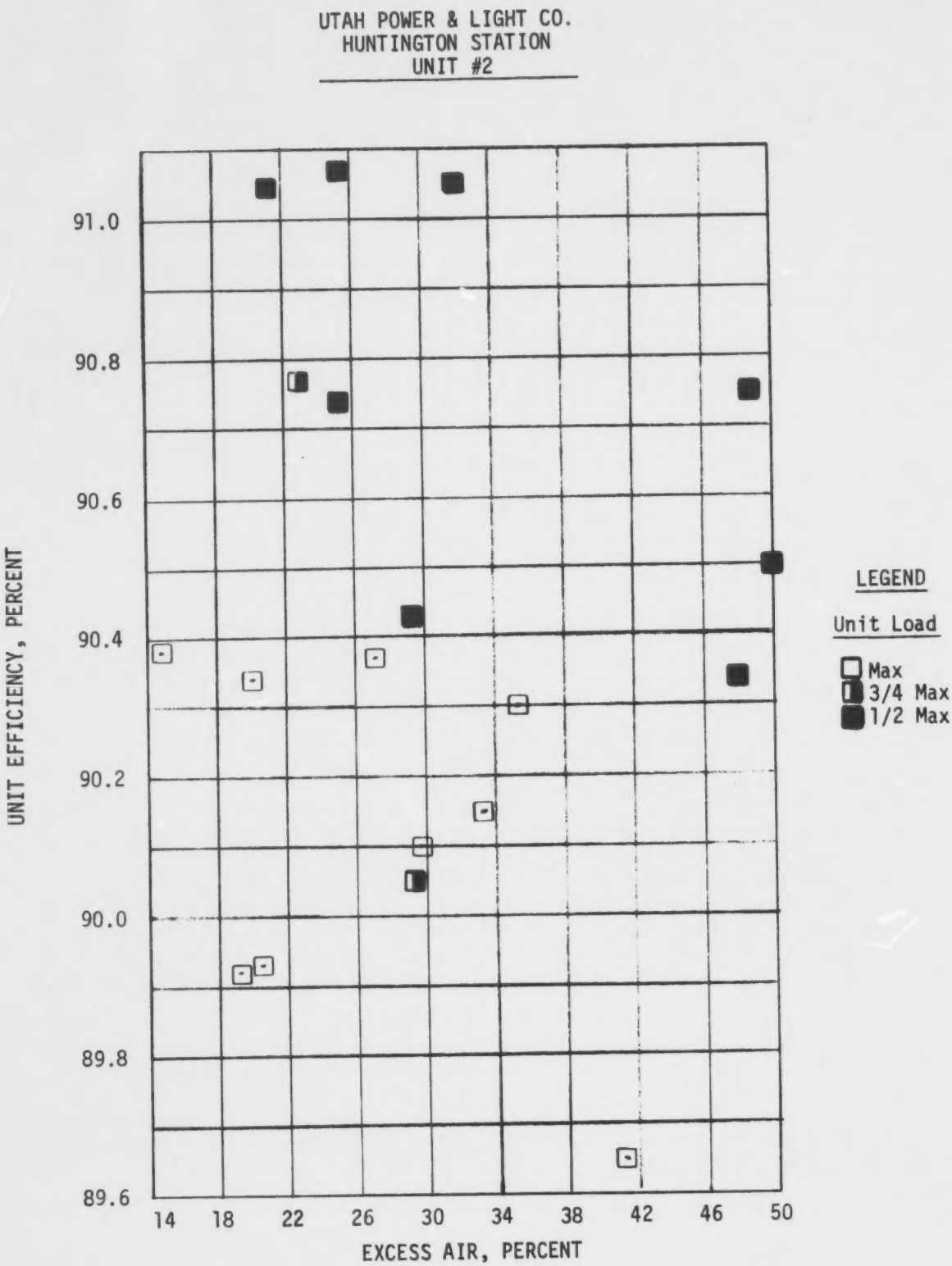


Figure 49: Unit efficiency vs. excess air, baseline study

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air to Firing Zone-%	Unit Effic. %	Fuel Nozzle Elevation Out of Service
1	375	168.4	16.7	19.8	107.1	89.91	Top
2	371	223.7	4.8	21.5	118.9	90.40	Center
3	368	243.1	9.2	20.9	117.8	89.97	Bottom
4	297	191.5	6.3	16.8	98.5	90.14	Top
5	295	203.6	4.4	19.9	119.3	90.23	Top Center
6	299	263.4	4.8	20.8	119.8	90.97	Bottom Center
7	218	178.4	4.8	22.6	106.5	90.99	Top
8	214	263.3	4.1	24.4	122.8	90.84	Center
9	375	208.1	5.0	26.3	107.6	89.80	Top
10	370	227.3	5.0	27.4	125.3	89.97	Top Center
11	369	255.9	5.2	29.3	126.8	90.13	Bottom Center
12	295	214.2	5.2	29.3	109.1	90.21	Top
13	299	283.8	5.7	28.0	127.0	89.97	Center
14	299	248.4	6.4	31.7	131.0	90.04	Bottom
15	203	187.2	4.5	25.1	124.4	90.77	Top Center
16	210	224.3	4.6	24.7	124.0	90.58	Bottom Center

Analysis of Results

Figure 50 is a plot of NO_2 emission levels versus theoretical air to the fuel firing zone. As with the baseline study tests, this figure shows that increasing TA results in increasing NO_2 emission levels. As evidenced by the scatter in the data, unit loading does not appear to have any distinct effect on NO_2 emission levels.

Most of the biased firing tests were performed during the time period when the coal being fired was a blend of two or three coals. Furnace waterwall slagging conditions for the biased firing tests ranged from light to moderately dirty furnace waterwalls. As a result of the small variation in furnace waterwall deposits, no effect on NO_2 emission levels was evident. Therefore, furnace slagging conditions have not been indicated on the biased firing graphs.

Figure 51 is a plot of fuel firing elevation out of service versus NO_2 emissions level. As this figure shows, the lowest NO_2 levels were obtained when the top fuel firing elevation was removed from service. This method of unit operation most closely simulates overfire air operation. The highest NO_2 emission levels were obtained when the center fuel firing elevation was removed from service. Removal of the bottom fuel firing elevation from service showed a reduction in NO_2 levels from the highest levels obtained when the center fuel elevation was removed from service. These lower NO_2 levels may possibly be attributed to the flow of air under the fuel firing zone causing a lowering in bulk flame temperature.

CO emission levels versus theoretical air to the fuel firing zone are plotted in Figure 52. No variation in CO emission levels with unit loading or furnace waterwall deposits is evident. The variation in CO emission levels with TA is not as expected. Test #1 has an unusually high CO emission level. This can be partially attributed to the fact that the dampers for the top fuel firing elevation were only 10 percent open as opposed to the 100 percent open desired.

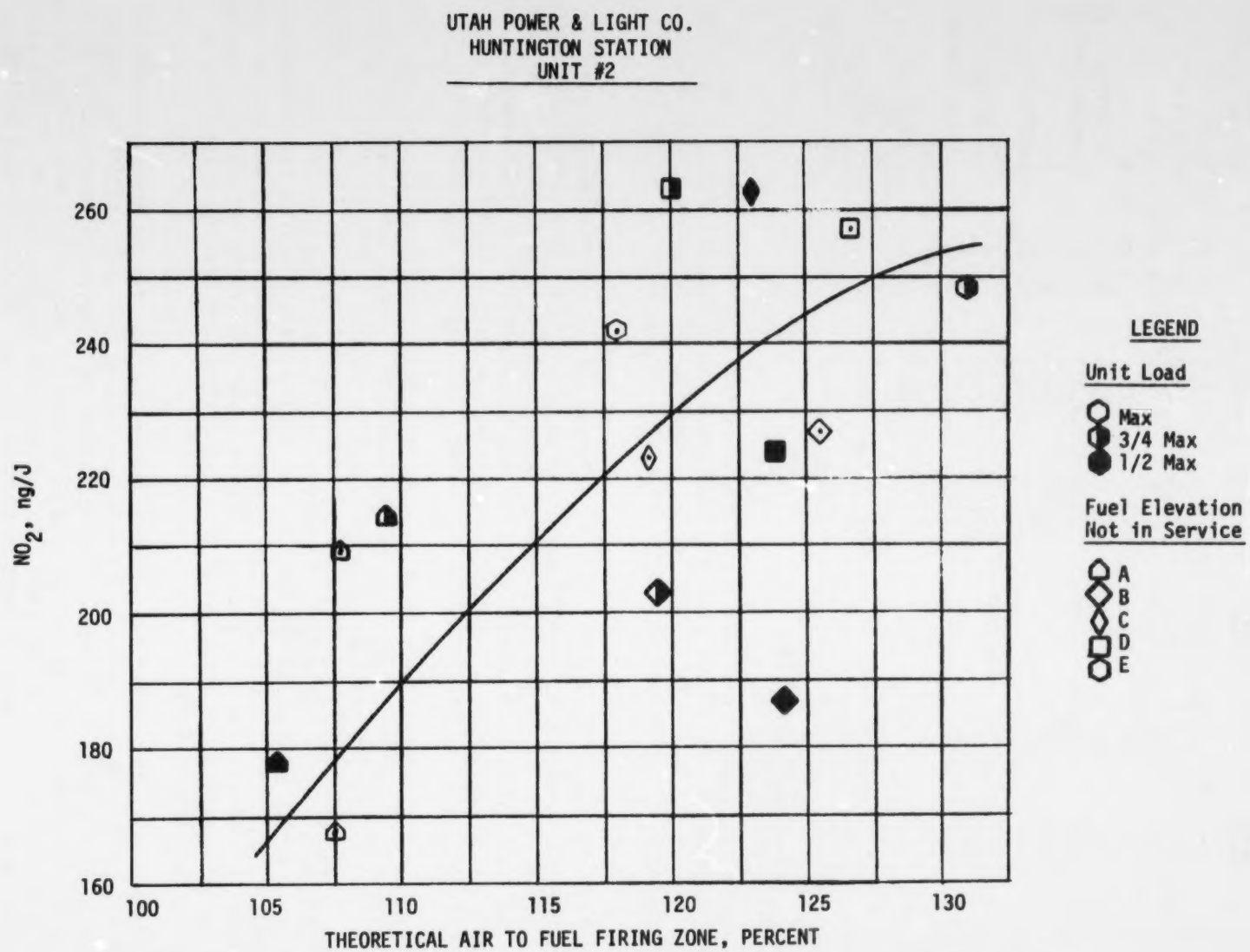


Figure 50: NO_2 vs. theoretical air to fuel firing zone, biased firing study

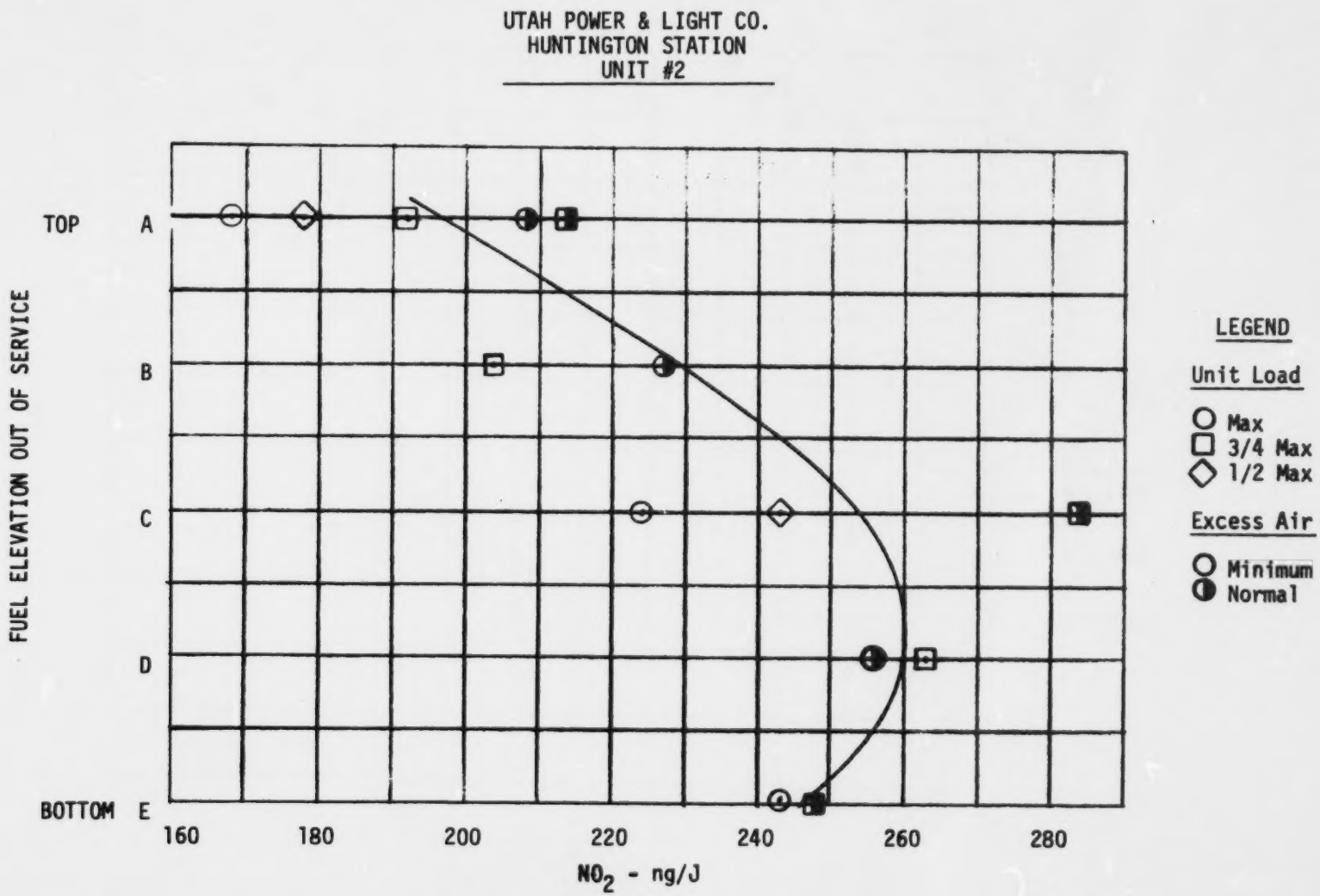


Figure 51: Fuel elevation out of service vs. NO_2, biased firing study

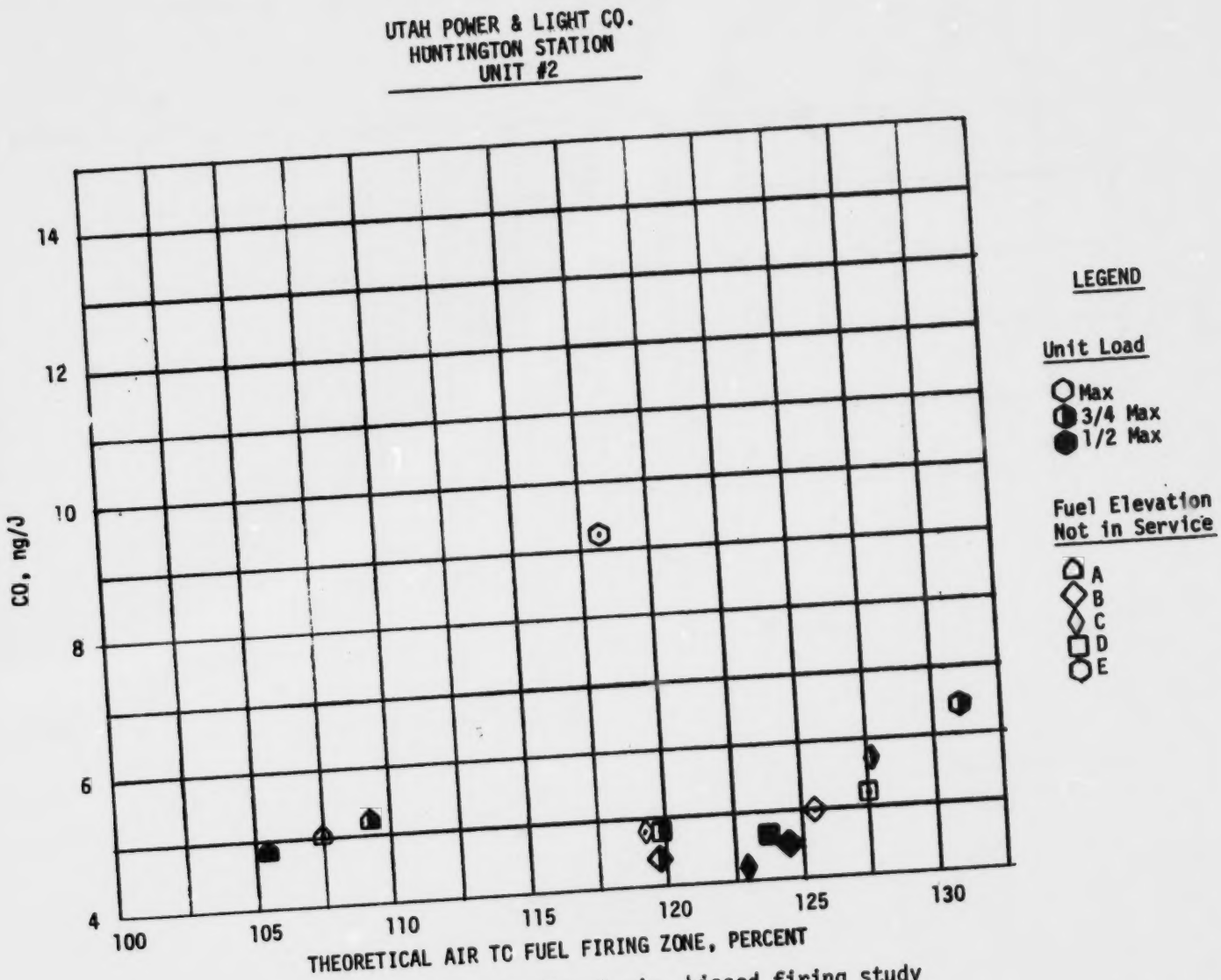


Figure 52: CO vs. theoretical air, biased firing study

This fact coupled with the low excess air operation may have contributed to the high CO level. While there is a rise in CO level for TA's below 120 percent, the variation is not pronounced. Also, Tests #13 and #14 have slightly higher CO emission levels while operating at the highest TA.

Figure 53 shows that some of those tests (Nos. 3, 4 and 14) with high CO emission levels also have some of the highest carbon heat loss values regardless of unit load or TA. Figure 53 indicates that increasing carbon heat loss is possible with decreasing TA. This trend is not completely supported by the data as plotted. Tests 3, 13 and 14 have higher carbon heat loss values than expected for the excess air levels at which the unit was operating. It should be noted that these tests were run with the center and bottom fuel elevations out of service. Plotting of the fuel elevation out of service versus the CO emission levels did not provide any useful information; therefore, it is not included in this report.

Figure 54 shows unit efficiency versus percent excess air at the economizer outlet. This plot reveals no useful information regarding the effect of excess air level on unit efficiency.

SO_2 emission levels were again monitored for each test and are reported on Data Sheets B-3 and B-4.

Unburned hydrocarbon emission levels monitored were at such low levels as to be unmeasurable.

TASK VI - OVERFIRE AIR OPERATION STUDY

Excess Air and Overfire Air Rate Variation

Tests 1 through 11 were conducted to determine the effect of varying the overfire air rate and excess air level on the NO_2 emission levels and Unit Performance. For these tests the overfire air registers were held at horizontal while the fuel nozzle tilts were allowed to vary from a -14 degrees to a +17 degrees. For each group of tests in this series, the variation in tilt was held to the minimum allowed while maintaining acceptable superheat and reheat outlet temperatures. Furnace waterwall deposits were not controlled for these tests and ranged from light to heavy slagging conditions on the waterwalls. The overfire air tests were performed during that time period when the coal being fired was a blend of two to three coals. There was also some problems at this time with soot blowers being out of operation.

As shown by the following table, NO_2 emission levels are found to increase with increasing theoretical air to the fuel firing zone. This correlation is evident regardless of the total excess air level the unit is operating at. Although Tests 1 through 5 were conducted at normal excess air levels, averaging 26.5 percent at the economizer outlet, the NO_2 emission levels were lower than for Tests 6 through 8 at minimum excess air levels, averaging 19 percent at the economizer outlet. This variation was not as expected.

One possible explanation to this unexpected variation is that the tilts for tests 6 through 8 were at a plus ten (+10) degrees while those tilts for tests 1 through 5 ranged from a plus six (+6) to a minus fourteen (-14) degrees. While the plus tilts in tests 6 through 8 reduced the residence time of the hot

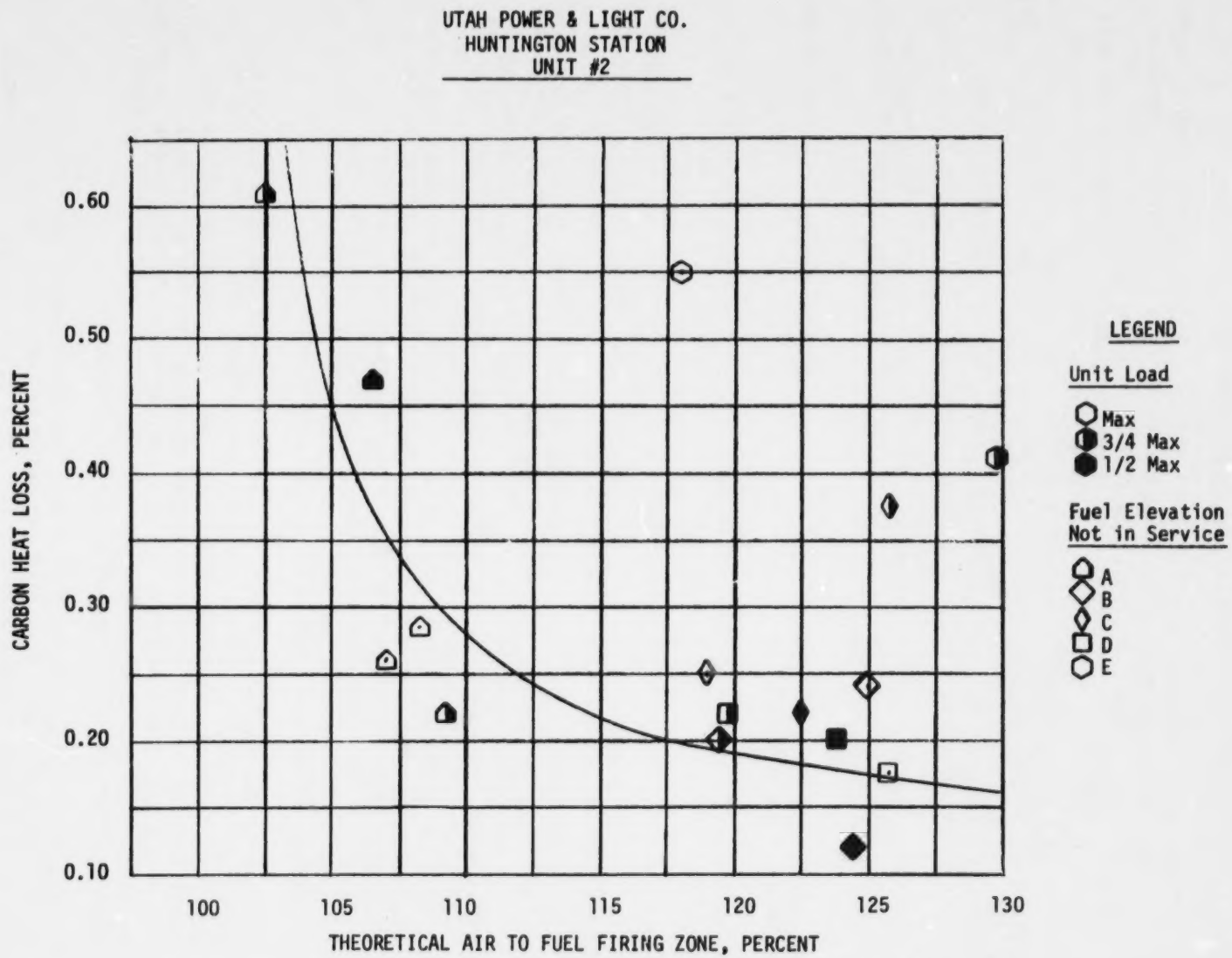


Figure 53: Carbon heat loss vs. theoretical air, biased firing study

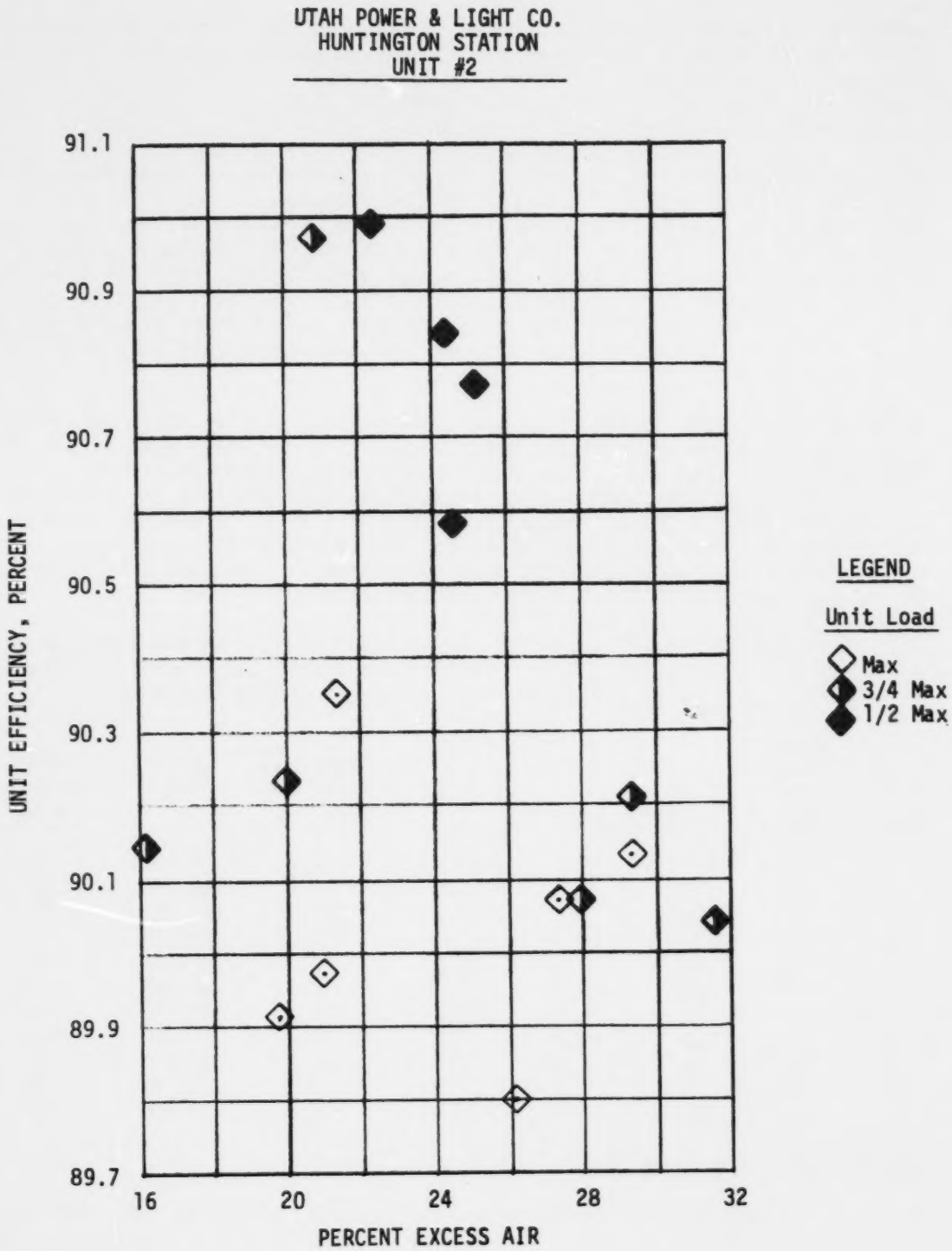


Figure 54: Unit efficiency vs. excess air, biased firing study

gases in the furnace they also exposed the fire to less furnace waterwall surface. The decrease in furnace waterwall surface cooling area seen by the fire can result in increased flame temperatures with a corresponding increase in thermal NO_x formation. Previous experience has shown minimum total excess air gives the minimum NO_2 emission levels for any given coal. One possible explanation to this difference in NO_2 emission levels is that the coal being burned at this time was a blend of American-Church Mine, Peabody-Wilberg Mine and Peabody-Deer Creek Mine coals. The percentages of each coal burned on a daily basis was an unknown factor. The Church Mine or Wilberg Mine coals were never used exclusively. Although these coals are of similar individual analysis, increased slagging conditions were experienced when firing a blend of these coals. The testing at this time was further aggravated by the necessity from that which had been required when burning design coal. Wall deposits were greater at this time, with running slag being experienced where previously only dry slag had existed.

Although those tests conducted at the normal excess air operating level resulted in the lowest NO_x values, normal excess air operation was not considered optimum for NO_x control. Based on the above facts, the optimum excess air operating level was considered to be the minimum, approximately 20 percent at the economizer outlet. The optimum overfire air rate based on the NO_2 emission level results for Tests 1 through 11 is with the overfire air dampers 100 percent open. This allows approximately 15 to 20 percent of the total combustion air to be introduced above the top level of fuel nozzles.

With the exception of Tests 7 and 8, CO emission levels are not found to vary significantly with changes in TA. Tests 7 and 8 have the lowest TA of Tests 1 through 11. This could contribute to the high CO levels monitored.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	OFA Dampers % Open
1	369	273.7	4.7	27.0	125.2	89.51	0
2	372	251.1	4.6	28.2	120.2	90.13	25
3	372	229.4	4.6	26.2	111.6	89.92	50
4	370	213.0	4.6	25.5	107.1	89.99	75
5	370	205.3	4.5	25.2	105.4	90.05	100
6	372	300.1	4.7	18.5	116.7	90.09	0
7	372	247.3	36.3	19.2	102.9	89.70	50
8	370	221.6	49.0	19.2	96.6	90.46	100
9	369	353.2	4.8	32.1	123.2	89.44	25
10	368	334.0	4.4	33.8	113.8	89.18	75
11	370	332.3	4.8	33.8	112.5	89.48	100

Overfire Air Tilt Variation

Tests 12 through 18 were conducted to determine the effect of fuel nozzle and overfire air register tilt on NO_2 emission levels and unit performance. These tests were conducted at the optimum overfire air rate (dampers 100 percent open) and excess air level (approximately 20 percent excess air at the economizer outlet) established in Tests 1 through 11. The fuel nozzles were varied from a -20 degrees to a +25 degrees, while the overfire air registers were varied from a

-30 to a +30 degrees. This variation of the fuel nozzle and overfire air register tilt angles moves the fuel firing zone both in the furnace and in its effective position relative to the overfire air registers. Movement of the fuel nozzles and overfire air registers away from each other accentuates the effect of staged combustion. Movement of the fuel nozzles and overfire air registers toward each other minimizes the effect of staged combustion because the air is being forced down into the firing zone. For these tests the furnace slagging conditions were allowed to vary, and ranged from light to moderate waterwall deposits.

As shown in the following table, minimum NO_2 levels were obtained when the fuel nozzles and overfire air registers were separated by 20 to 30 degrees (Tests 14 and 17). Parallel operation of the fuel nozzles and overfire air registers was nearly as effective, when both the fuel nozzle and overfire air registers were in a horizontal position (Test 15) or when both were tilted downward to their respective limits (Test 12). NO_2 emission levels were highest when the nozzles were moved toward each other. Therefore, the optimum condition was at a tilt differential of 20 to 30 degrees away from each other (Tests 14 and 17). For ease of boiler operation the tilt conditions for Test 17 were utilized in Tests 19 through 24.

With the exception of Tests 12 and 18, CO emission levels appear to be relatively unaffected by variations in fuel nozzle and overfire air register tilts. It should be noted that for Tests 12 and 18 the TA was less than 100 percent and that the fuel nozzles and overfire air registers were essentially operating in parallel. Test 12 was conducted with the fuel and overfire air nozzles at maximum minus tilt, while test 18 was conducted with the fuel and overfire air nozzles at maximum plus tilt. Operation of the boiler with the tilts at the maximum plus will reduce the residence time of the gases in the furnace and may result in higher CO levels due to insufficient burnout of the CO.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Fuel Nozzle Tilt-°	OFA Register Tilt-°
12	370	223.3	10.4	23.1	99.6	90.11	-20	-30
13	364	263.4	4.5	25.1	101.1	89.83	0	-30
14	370	179.8	4.8	22.0	99.2	90.32	-20	0
15	370	212.1	4.6	25.1	101.1	89.82	0	0
16	372	283.5	4.4	21.3	98.4	89.90	+25	0
17	377	186.1	4.9	23.5	99.8	90.01	0	+30
18	367	252.1	15.8	21.7	98.6	89.51	+25	+30

Load and Furnace Waterwall Deposit Variation at Optimum Conditions

Tests 19 through 24 were conducted at the optimized conditions of excess air level, overfire air rate and fuel nozzle and overfire air register tilt as determined in Tests 1 through 18. These tests were run to determine the effect on NO_x emission levels and unit performance at optimum conditions, while varying unit load and furnace wall deposits. These tests were conducted at an average excess air level of 21 percent, overfire air register dampers 75 to 100 percent open and with the overfire air registers tilted to +30 degrees while the fuel nozzles were held at horizontal.

As shown in the following table, NO_2 emission levels are affected by unit load, with higher NO_2 levels for higher loads. Furnace waterwall deposits have a greater effect on NO_2 levels at lower loads. A distinct effect on NO_2 emission level is evident at half (1/2) load (Test Nos. 23 and 24), while this distinction is considerably less for three-quarter (3/4) load (Tests 21 and 22) and is reversed for full load (Tests 19 and 20). This suggests a possible relationship between furnace waterwall deposits, unit load and NO_2 levels.

Except for Test 23, CO emission levels are unaffected by unit load or furnace waterwall deposits. The CO level and the carbon heat loss for Test 23 are high when considering the conditions at which the boiler was operating.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Furnace Condition
19	374	196.5	5.8	18.5	95.8	89.79	Clean
20	377	190.2	5.8	19.6	97.1	89.85	Moderate
21	299	161.3	5.7	19.3	98.1	90.41	Clean
22	299	167.8	6.3	21.5	95.0	90.65	Moderate
23	218	132.0	19.0	22.8	97.3	90.79	Clean
24	217	155.3	4.5	23.9	99.7	90.76	Moderate

Analysis of Results

The changes in NO_2, CO and carbon heat loss versus changes in theoretical air to the fuel firing zone are shown in Figures 55, 56 and 57, respectively.

Figure 55 shows that there is a definite trend in NO_2 emission levels with changes in TA. Increasing TA results in increasing NO_2 emission levels. Furnace waterwall deposits and unit load are also indicated on Figure 55. No correlation between furnace waterwall deposit variation and NO_2 emission level is evident from the data as plotted. The effect of unit load on NO_2 levels shows lower NO_2 levels for lower loads. As these low load tests (Tests 21, 22, 23 and 24) also have some of the lowest TA's, these should be compared with full load tests at similar TA's to find the effect of unit load. A comparison of Tests 21 and 24 with Tests 14 and 17 or of Tests 22 and 23 with Tests 19 and 20 shows that lower loads resulted in lower NO_2 levels.

CO emission level versus theoretical air to the fuel firing zone is plotted in Figure 56. Figure 56 indicates rise in CO emission levels below TA levels of 104 percent. Previous studies at Alabama Power Company's, Barry #2 [2] have shown that CO levels tend to rise rapidly in those TA regions where NO_2 levels are falling rapidly.

As is evident in Figure 57, decreasing theoretical air to the fuel firing zone results in increasing carbon heat loss levels. This trend, while being similar, is much more apparent than with the CO emission levels, with carbon heat losses rising rapidly below 104 percent TA. This trend was also observed at Alabama Power Company, Barry Station, Unit #2 [2].

Figure 58 shows the effect that variation of fuel nozzle and overfire air register tilts has on NO_2 emission levels.

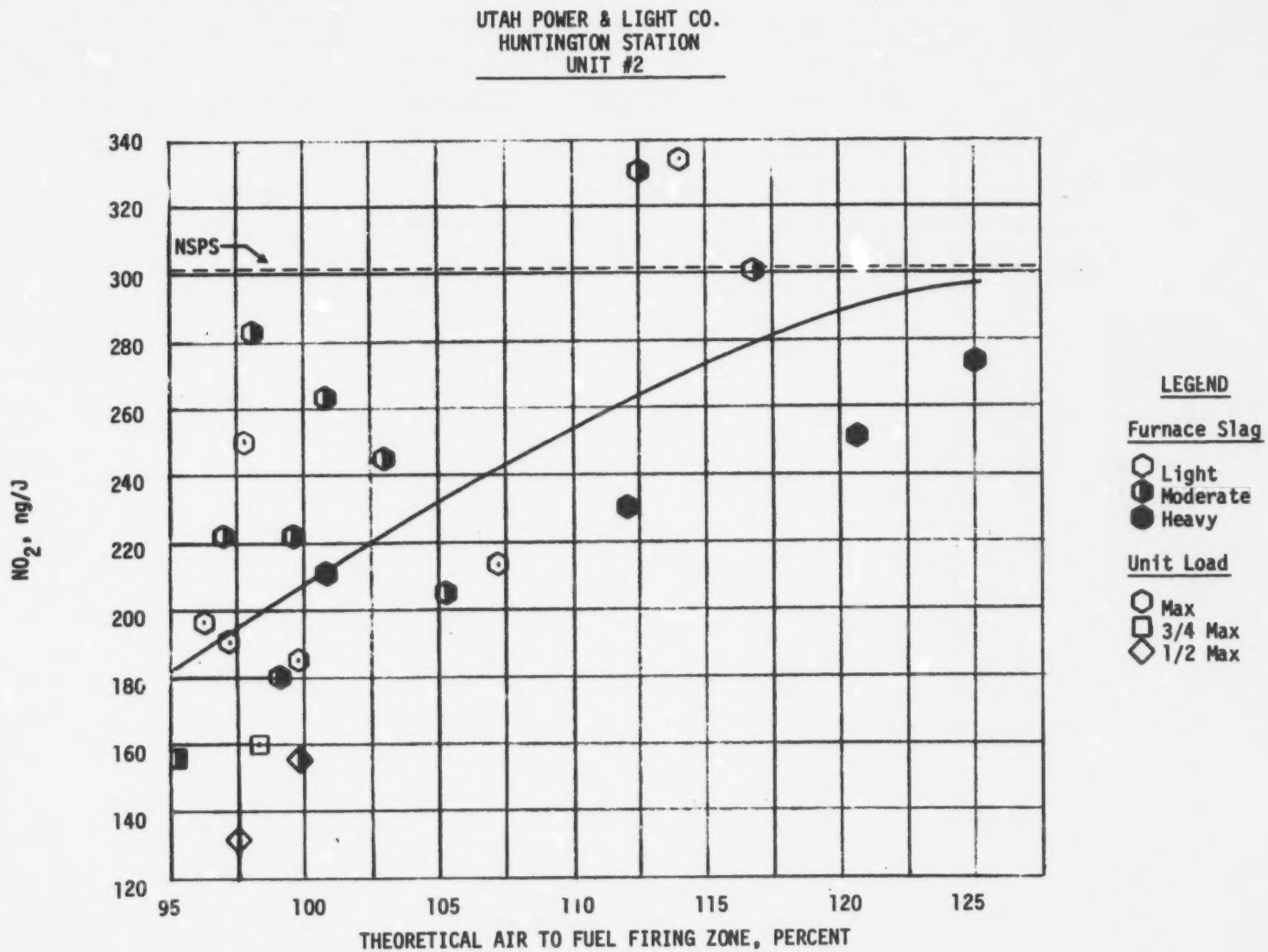


Figure 55: NO_2 vs. theoretical air to fuel firing zone, overfire air study

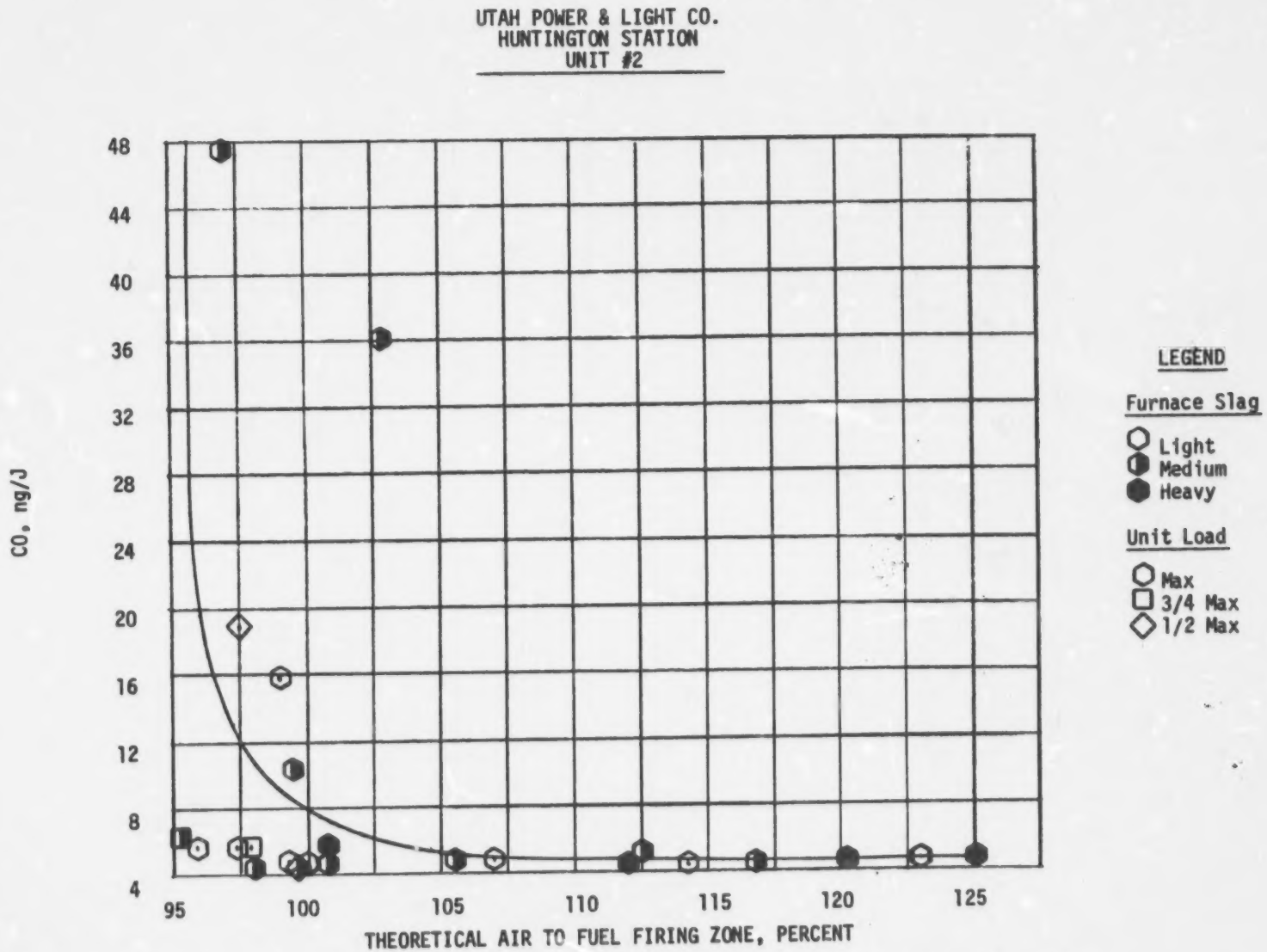


Figure 56: CO vs. theoretical air to fuel firing zone, overfire air study

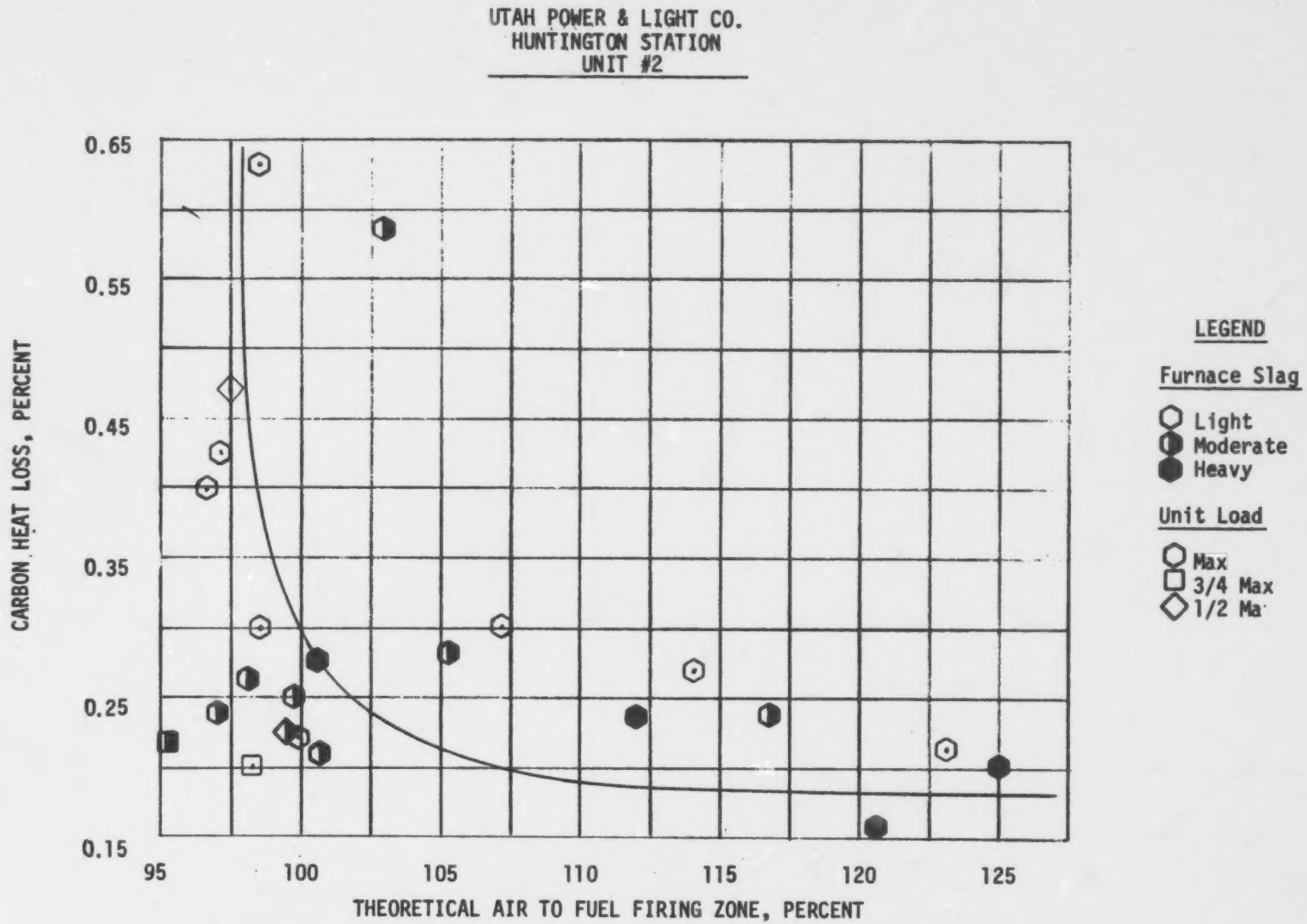


Figure 57: Carbon heat loss vs. theoretical air, overfire air study

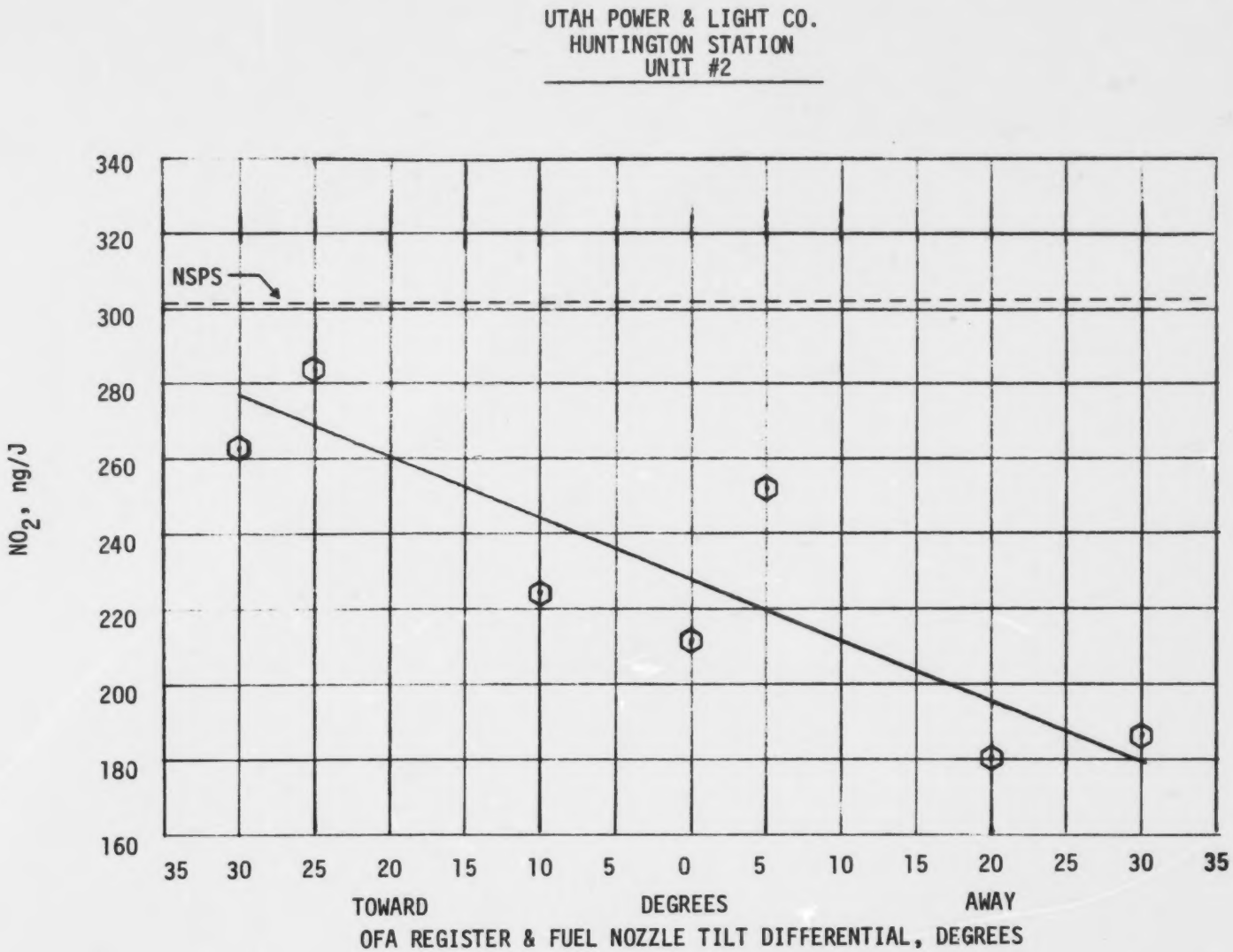


Figure 58: NO_2 vs. tilt differential, overfire air study

Figure 58 shows that as the fuel nozzles and overfire air registers are angled toward each other, NO_2 emission levels rise. Conversely as the nozzles are moved away from each other, the effect of staged combustion becomes more pronounced, until at 30 degrees away from each other the NO_2 emission level is 186 ng/J for full load unit operation.

Prior experience at Alabama Power Company's, Barry Station, Unit #2 has shown that flame stability can be a limiting factor as the fuel nozzles and overfire air registers move substantially away from each other. Tests, similar to Tests 12 through 18, at the Barry Station, Unit #2 indicated a probable maximum differential of 50 degrees between the fuel nozzles and overfire air registers [2]. Flame instability was not apparent during tilt variation tests at Utah Power and Light Company's Huntington Canyon Station, Unit #2. The maximum differential of the fuel nozzles and overfire air registers away from each other for these tests was only 30 degrees compared to 50 degrees for the Barry tests.

Figure 59 shows unit efficiency versus excess air at the economizer outlet. A decrease in unit efficiency is evident with increasing excess air at the economizer outlet. This trend is in agreement with the baseline and biased firing tests at Huntington Canyon Station, Unit #2 and previous tests at Barry Station, Unit #2.

SO_2 emission levels were monitored and are reported on Sheets B-5 and B-6. As with the other tests there is no apparent correlation between SO_2 emission levels and excess air, unit load or furnace waterwall deposits.

Unburned hydrocarbons were monitored for all overfire air tests and were at such low levels as to be unmeasurable.

A thirty (30) day waterwall corrosion coupon test was conducted in November, 1975. The boiler operated with the overfire dampers 100% open and with full load being maintained as much as possible. The overfire air corrosion coupon test is discussed in the following section, Waterwall Corrosion Coupon Evaluation.

WATERWALL CORROSION COUPON EVALUATION

Following completion of the steady state phases of the baseline and overfire air test programs, thirty (30) day waterwall corrosion coupon evaluations were performed. The purpose of these evaluations was to determine whether any measurable changes in coupon weight losses could be obtained for the modes of firing under study.

The individual probes were exposed at five locations on the furnace front wall as shown on Figure 60. The coupon temperatures were maintained at the same levels for each 30 day run and a typical tract of the control temperature range for each of the twenty coupons is shown on Figure 61.

The individual coupon weights were determined before and after each thirty day test and the individual coupon and average probe weight losses are shown on Sheets B45 and B46. The weight losses are calculated as mg/cm^2 of coupon surface area.

Figures 62 and 63 show the unit load schedules for each of the 30 day test

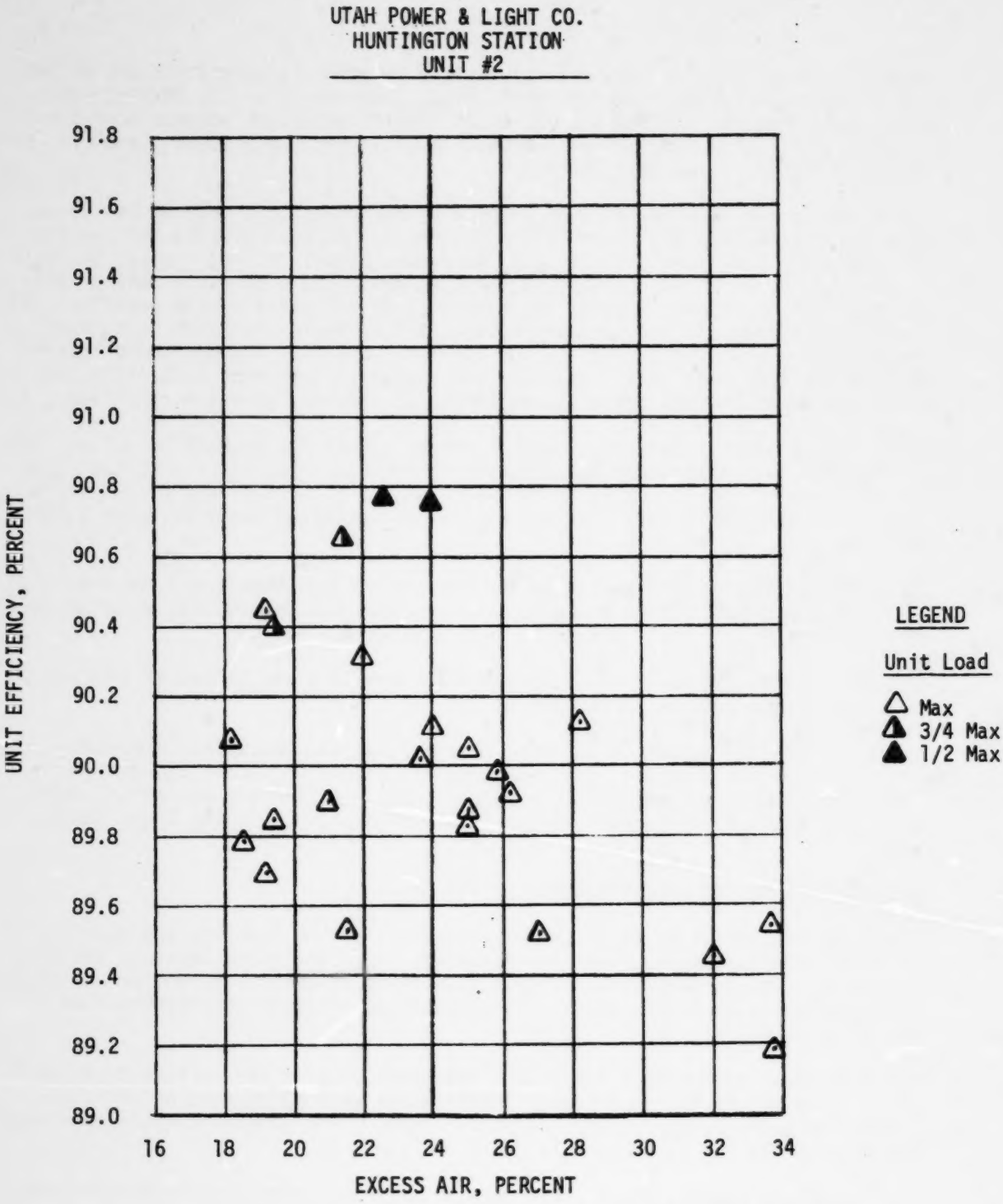


Figure 59: Unit efficiency vs. excess air, overfire air study

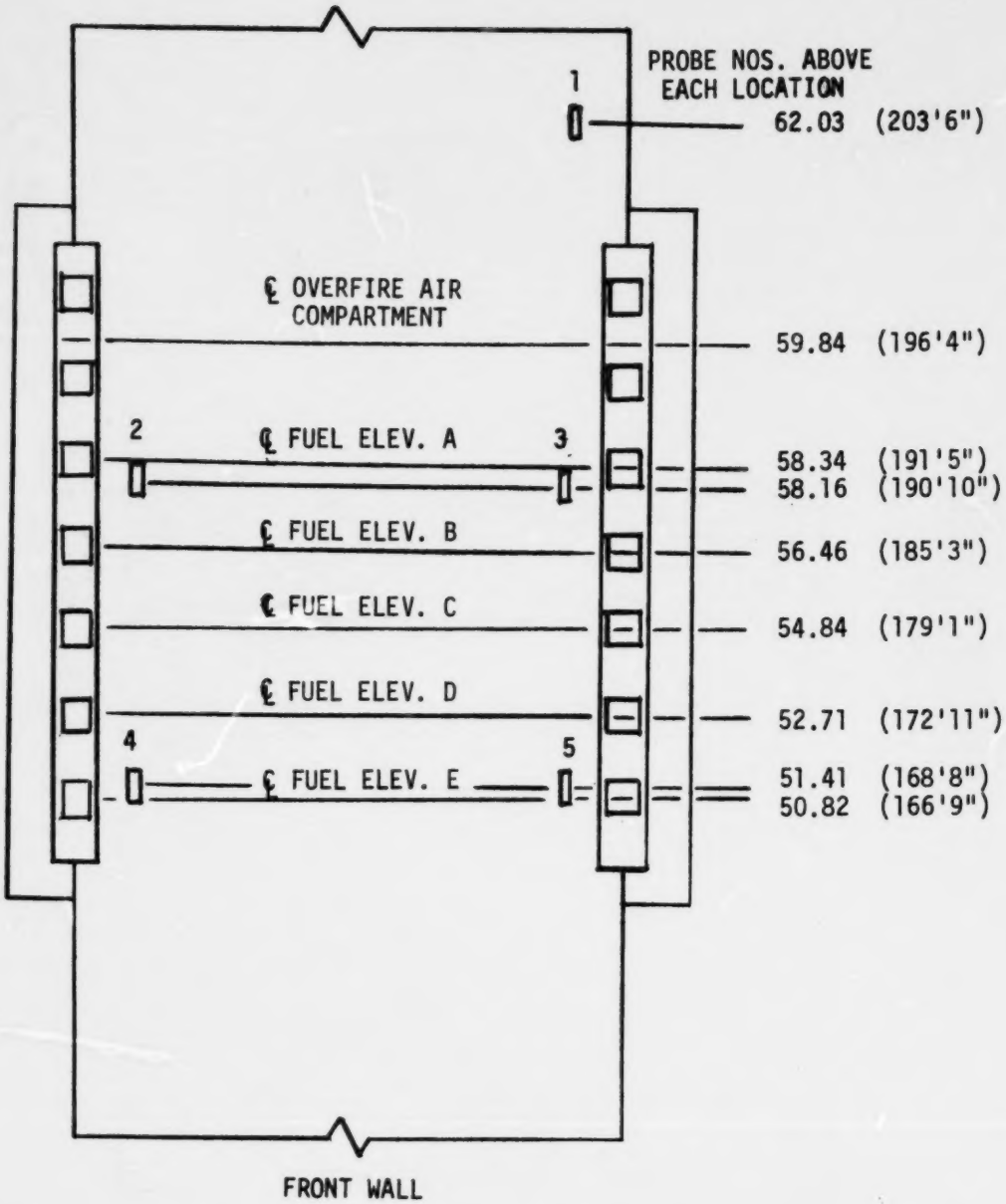


Figure 60. Waterwall corrosion probe locations, Huntington Station No. 2

UTAH POWER & LIGHT CO.
HUNTINGTON STATION
UNIT #2

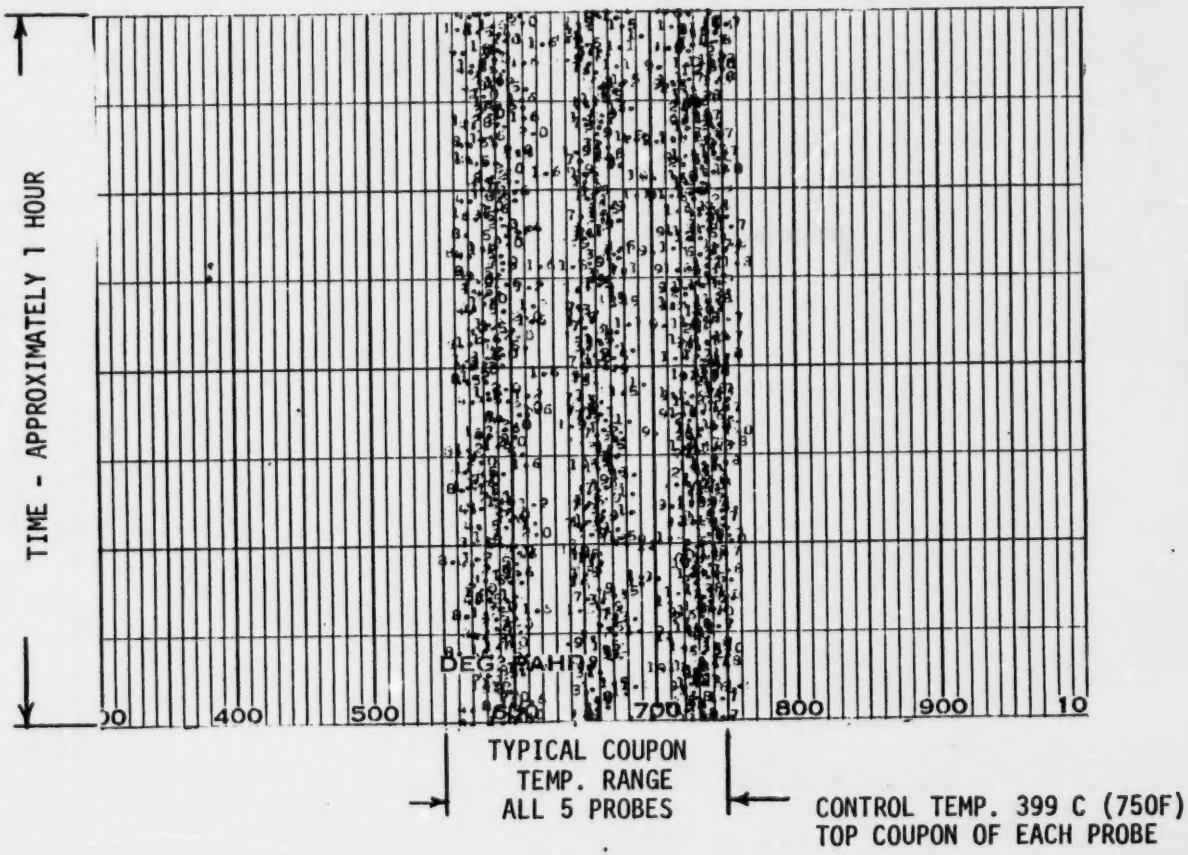


Figure 61. Typical corrosion probe temperature ranges, Huntington Station No. 2

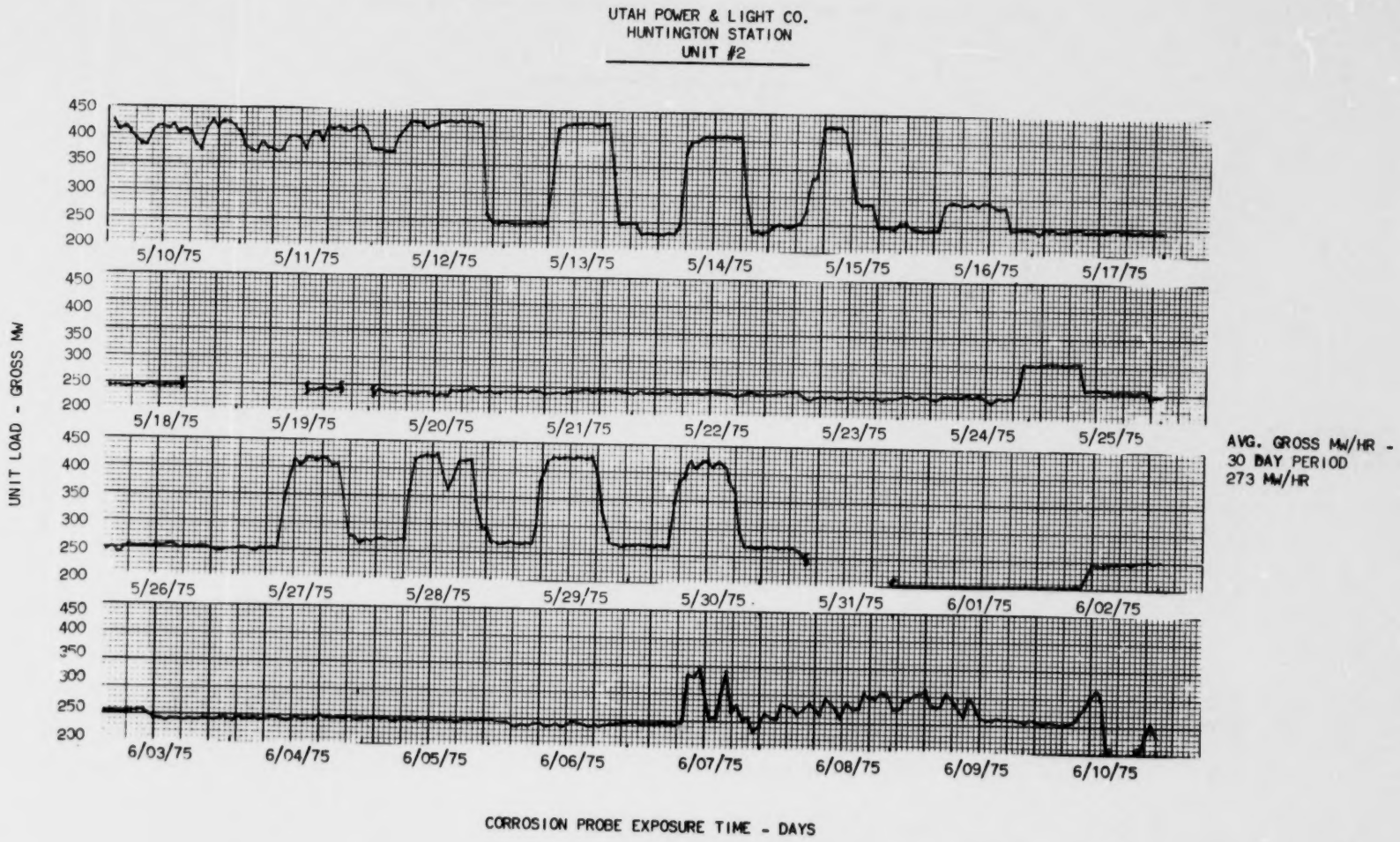


FIGURE 62: GROSS MW LOADING VS. TIME - BASELINE CORROSION PROBE STUDY

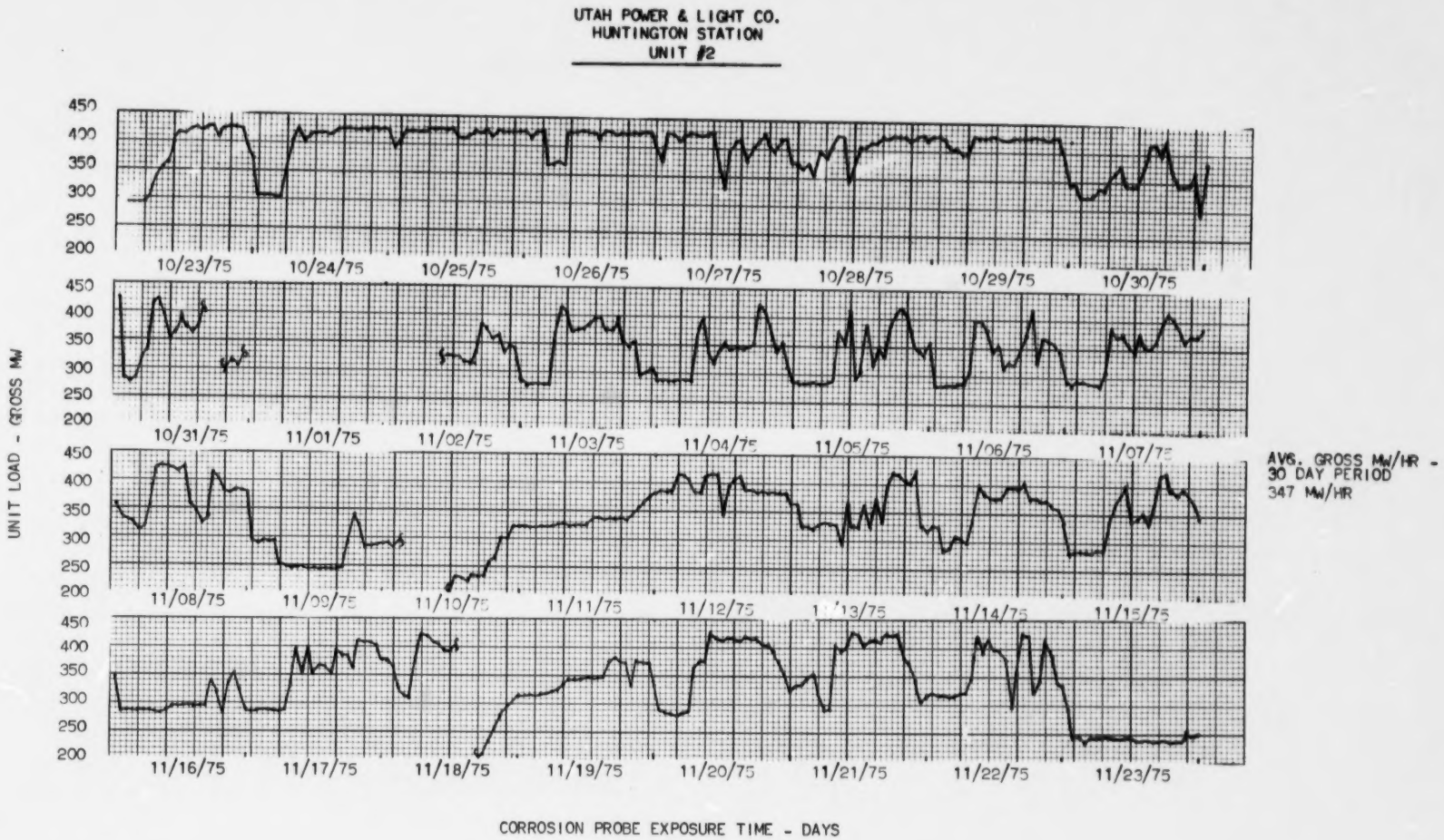


FIGURE 63: GROSS MW LOADING VS. TIME - OVERFIRE AIR CORROSION PROBE STUDY

periods.

The overfire air portion of the study was conducted using the "optimum" operating conditions determined during the overfire air steady state tests.

Throughout the overfire air study the overfire air dampers were maintained at the full open configuration over the range of unit loading shown on Figure 63 with the following exceptions. On November 2, 1975 the overfire air were closed during unit start-up. Between November 5 and November 7, 1975 one compartment was closed when required to maintain proper windbox pressure. November 15 to November 16, 1975 one compartment was closed at reduced unit loading and on November 22 and November 23, 1975 one or both dampers were closed during low load operation.

The percent oxygen was monitored daily during each thirty day study at each probe location and was found to range between 7 and 19 percent O_2 during both the baseline and overfire air studies.

The weight losses calculated for the baseline portion of the test program were found to be greater than those for the overfire air tests. The average weight losses for all five probes were as follows:

Baseline	Overfire Air
3.4266 mg/cm^2	2.6357 mg/cm^2

These values are within the range of losses which would be expected for oxidation of carbon steel for a 30 day period. This premise is verified by control studies conducted in C-E's Kreisinger Development Laboratory using probes exposed during the biased firing study conducted at Alabama Power Co., Barry #2. These probes were cleaned and prepared in an identical manner to those used for furnace exposure and placed in a muffle furnace for 30 and 60 day exposures at 399°C with a fresh air exchange. The test results were as follows:

Probe	Wt. Loss mg/cm^2 - 30 Days
M (30 day)	4.7999
Q (30 day)	4.7741
R (60 day)	5.1571/2 = 2.5785
B (60 day)	8.3493/2 = 4.1746

These results indicate that the test coupons oxidized more rapidly during the first 30 days exposure with average weight losses decreasing in the second thirty days. Based on these results, it appears that the differences in weight losses observed during the test program are within the ranges to be expected from oxidation alone.

Chemical analysis of coupon deposits taken during the test program indicate an enrichment in iron as compared with the "as fired" coal ash analysis with the greater enrichment occurring during the baseline study. Also the degree of iron enrichment during the overfire air study was not as consistent as was noted in the baseline study. There is some question as to whether the ash deposits accurately represent inner and outer layers of deposit in some probes. Despite the uncertainty there was nothing about the compositions or fusibility

temperatures which would indicate a change in slagging condition between the baseline and overfire air studies. The as-fired ash and coupon deposit analyses are given on Figures 64 and 65.

WATERWALL CORROSION COUPON DATA SUMMARY

AS FIRED ASH AND COUPON DEPOSIT ANALYSIS

BASELINE STUDY

Sample Location	Mill Exhauster	Probe #1	Probe #2	Probe #3	Probe #4	Probe #5
Ash Fusibility-^{o}F						
Initial Deformation Temp.	2050	1980	I.S.	1980	I.S.	1910
Softening Temp.	2160	2040		2160		I.S.
Fluid Temp.	2440	2210		2270		2050
Ash Composition-%by Weight						
SiO_2	49.0	21.0	18.4	21.0	18.5	I.S.
Al_2O_3	15.5	4.5	6.0	4.8	7.9	
Fe_2O_3	7.2	54.6	47.9	54.8	45.6	
CaO	9.0	9.0	6.5	8.0	8.3	
MgO	2.0	2.1	1.1	1.7	1.3	
Na_2O	4.8	2.0	3.2	1.9	3.3	
K_2O	1.0	0.5	0.9	0.6	0.6	
TiO_2	1.0	0.3	0.6	0.4	0.3	
SO_3	7.6	6.0	15.4	6.8	14.1	
Total	97.1	100.0	100.0	100.0	99.9	

I.S. - Insufficient Sample

Figure 64: As-fired ash & coupon deposit analysis, baseline study

WATERWALL CORROSION COUPON DATA SUMMARY

AS FIRED ASH AND COUPON DEPOSIT ANALYSIS

OVERFIRE AIR STUDY

Sample Location	Mill Exhauster	Probe #1	Probe #2	Probe #3	Probe #4	Probe #5
Ash Fusibility-^{o}F						
Initial Deformation Temp.	2130	2200	1890	2120	1940	I.S.
Softening Temp.	2200	2250	1920	2210	1970	
Fluid Temp.	2450	2530	2020	2440	2140	
Ash Composition-%by Weight						
SiO_2	51.5	56.9	28.7	55.6	29.3	23.9
Al_2O_3	17.0	19.2	11.3	18.3	26.8	9.2
Fe_2O_3	4.7	4.4	32.8	5.4	25.5	39.9
CaO	8.9	9.6	13.9	9.1	9.3	11.9
MgO	1.1	1.1	2.6	1.0	1.6	2.3
Na_2O	5.2	4.6	2.5	4.4	2.2	2.0
K_2O	0.6	0.6	0.4	0.6	0.3	0.3
TiO_2	1.0	0.6	0.4	0.6	0.9	0.5
SO_3	6.6	<0.1	4.7	0.3	3.8	5.5
Total	96.6	97.0	97.1	95.3	99.9	95.5

I.S. - Insufficient Sample

Figure 65: As-fired ash & coupon deposit analysis, overfire air study

SECTION III - EPA CONTRACT 68-02-1367

ALABAMA POWER COMPANY, BARRY STATION, UNIT #2

INTRODUCTION

This program encompassed the work to be performed under the second phase of a two phase program to identify, develop and recommend the most promising combustion modification techniques for the reduction of NO_x emissions from tangentially coal fired utility boilers with a minimum impact on unit performance.

Phase I (performed under EPA Contract 68-02-0264) consisted of selecting a suitable utility field boiler to be modified for experimental studies to evaluate NO_x emission control. Phase I also included the preparation of preliminary drawings, a detailed preliminary test program, a cost estimate and detailed schedule of the program phases and a preliminary application economic study indicating the cost range of a variety of combustion modification techniques applicable to existing and new boilers [1].

Phase II consisted of modifying and testing the utility boiler selected in Phase I to evaluate overfire air and biased firing as methods for NO_x control. This phase also included the completion of detailed fabrication and erection drawings, installation of analytical test equipment, updating of the preliminary test program, analysis and reporting of test results and the development of control technology application guidelines for existing and new tangentially coal fired utility boilers.

This program was conducted at the Barry Steam Station, Unit No. 2 of the Alabama Power Company. This unit is a natural circulation, balanced draft design, firing coal through four elevations of tilting tangential fuel nozzles. Unit capacity at maximum continuous rating (MCR) is 113 kg/s main steam flow with a superheat outlet temperature and pressure of 538°C and 12.9 MPa. Superheat and reheat temperatures are controlled by fuel nozzle tilt and spray desuperheating A side elevation of the unit prior to modification is shown on Figure 66.

Throughout this report NO_x emission levels are expressed as ng/J NO_2.

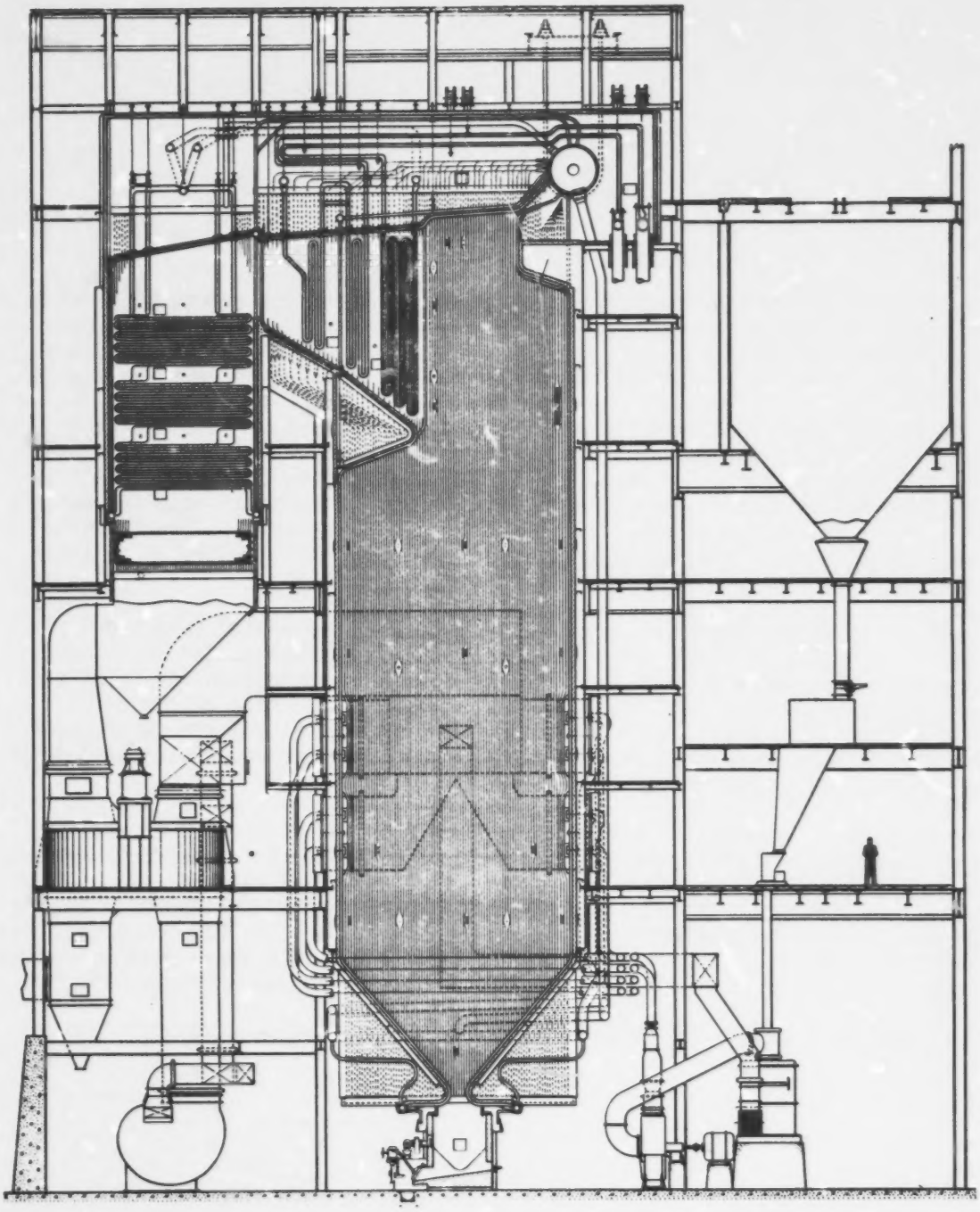


Figure 66. Unit side elevation, Alabama Power Company, Barry Station No. 2

CONCLUSIONS

NORMAL OPERATION

1. Under normal unit operation, without overfire air, excess air variation was found to have the greatest single effect on NO_x emission levels, increasing NO_x with increasing excess air. An average increase of 3.34 ng/J for each 1% change in excess air was observed over the normal operating range.

2. Unit loading and variation in furnace slag conditions were found to have the least effect on NO_x and CO emission levels and the percent carbon in the fly ash.

3. Under normal unit operation, the percent carbon loss in the fly ash and CO emission levels increased with decreasing excess air with the increases becoming greater below a level of approximately 20 to 25 percent excess air. CO levels in excess of 23.9 ng/J were considered unacceptable for the purposes of this program.

OVERFIRE AIR OPERATION

1. NO_x reductions of 20 to 30% were obtained with 15 to 20 percent overfire air when operating at a total unit excess air of approximately 15 percent as measured at the economizer outlet. This condition would provide an average fuel firing zone stoichiometry of 95 to 100 percent of theoretical air. Stoichiometries below this level did not result in large enough decreases in NO_x levels to justify their use. Biased firing, while potentially as effective, necessitates a reduction in unit loading and is therefore less desirable as a method of NO_x control.

2. When using overfire air as a means of decreasing the theoretical air (TA)* to the fuel firing zone the percent carbon in the fly ash and CO emission levels were less affected than when operating with low excess air. This is due to the ability to maintain acceptable total excess air levels during overfire air operation.

3. Furnace performance as indicated by waterwall slag accumulations, visual observations and absorption rates were not significantly affected by overfire air operation.

4. On the test unit, where the overfire air port could not be installed as a windbox extension, test results indicated that the centerline of the overfire air port should be kept within 3 meters of the centerline of the top fuel elevation. Distances greater than 3 meters did not result in decreased NO_x levels. Changes in distance less than 3 meters did affect NO_x levels to

* See Appendix D.

a limited extent with the NO_x level increasing with decreasing distance.

5. Optimum overfire air operation was obtained with the test unit when the overfire air nozzles were tilted with the fuel nozzles. From a standpoint of NO_x control, emission levels increased when the nozzles were directed toward each other, and flame stability decreased when they were directed away from each other by more than 20-25°. With the overfire air tilts fixed in a horizontal position, acceptable unit operation was obtained, however, NO_x levels varied with fuel nozzle position.

6. The results of the 30 day baseline, biased firing and overfire air corrosion coupon runs indicate that the overfire air operation for low NO_x optimization did not result in significant increases in corrosion coupon degradation. Additional studies will be required to verify these observations over long-term operation.

7. Variables normally used to control normal boiler operation should not be considered as NO_x controls with coal firing. These variables include unit load, nozzle tilt, pulverizer fineness, windbox dampers and total excess air.

8. Overall unit efficiency was not significantly affected by overfire air operation.

OBJECTIVES

The objective of program Phase II was to complete the design of the overfire air system, modify the Barry #2 unit accordingly, perform baseline, biased firing and optimization tests and based on the results of this program, prepare an application guideline for the NO_x control technology generated.

Specifically these objectives are defined as follows:

TASK I

Prepare the design, detailed fabrication and erection drawings necessary for modification of Barry No. 2 to incorporate an overfire air system. The system design provides for:

a. Introducing a maximum of 20% of the total combustion air above the fuel admission nozzles.

b. Overfire air introduction through the top two existing windbox compartments (thereby prohibiting the use of one elevation of fuel nozzles).

c. Introduction of hot overfire air only with consideration for air preheat control.

An updated schedule for Tasks II and IV were also prepared under Task I.

TASK II

Complete the purchasing and fabrication of all equipment necessary for modification of the Barry No. 2 unit.

TASK III

Install all necessary instrumentation required to measure flue gas constituents and characterize the effects of combustion modifications on unit performance. Specifically the following determinations were made:

a. Flue gas constituents: NO_x, SO_x, CO, HC, O_2

b. Unit Performance Effects:

Fireside Corrosion
Furnace Heat Absorption
Sensible Heat Leaving Furnace
Superheater, Reheater and Air Heater Performance

TASK IV

Conduct a baseline test program to establish the effect of unit load, wall slagging and excess air variation on baseline emission levels, thermal performance and operating ranges. A baseline corrosion coupon test of 30 day duration was also conducted.

TASK V

Conduct a biased firing baseline test program to establish the effect on unit emission levels while operating with various fuel elevations out of service. These tests were performed specifically to evaluate the maximum emission control at full load and throughout the normal load range. In addition, the degree of control required to meet and maintain emission standards throughout the normal control range was also evaluated. A biased firing corrosion coupon test of 30 days duration was also conducted.

TASK VI

Install all equipment required for modification of the test unit and functionally check equipment to determine that proper operation is obtained. (See Figure 67).

TASK VII

Complete final preparations for conducting the overfire air test program to be conducted in Task VIII including the following:

a. Finish installation of the furnace waterwall thermocouples.

b. Check out all necessary test instrumentation for proper installation and operation.

c. Review test program with EPA project officer and utility company.*

d. Perform a final inspection of the test unit to assure proper operation.

TASK VIII

Conduct the overfire air test program, analyze the data generated and compare this data with that obtained during Task V. The program investigated the effect of overfire air location and rate at various unit loadings and evaluated operating conditions considered as optimum from the standpoint of NO_x control and unit operation. The final report was also generated under this Task.

TASK IX

Prepare a program outlining the application of the technology developed under this study to existing and new design tangentially coal fired utility boilers. These application guidelines will be submitted as a separate final report.

* The test program for this study was originated during the Phase I study, Contract 68-02-0264 and was included as part of the Phase I report.

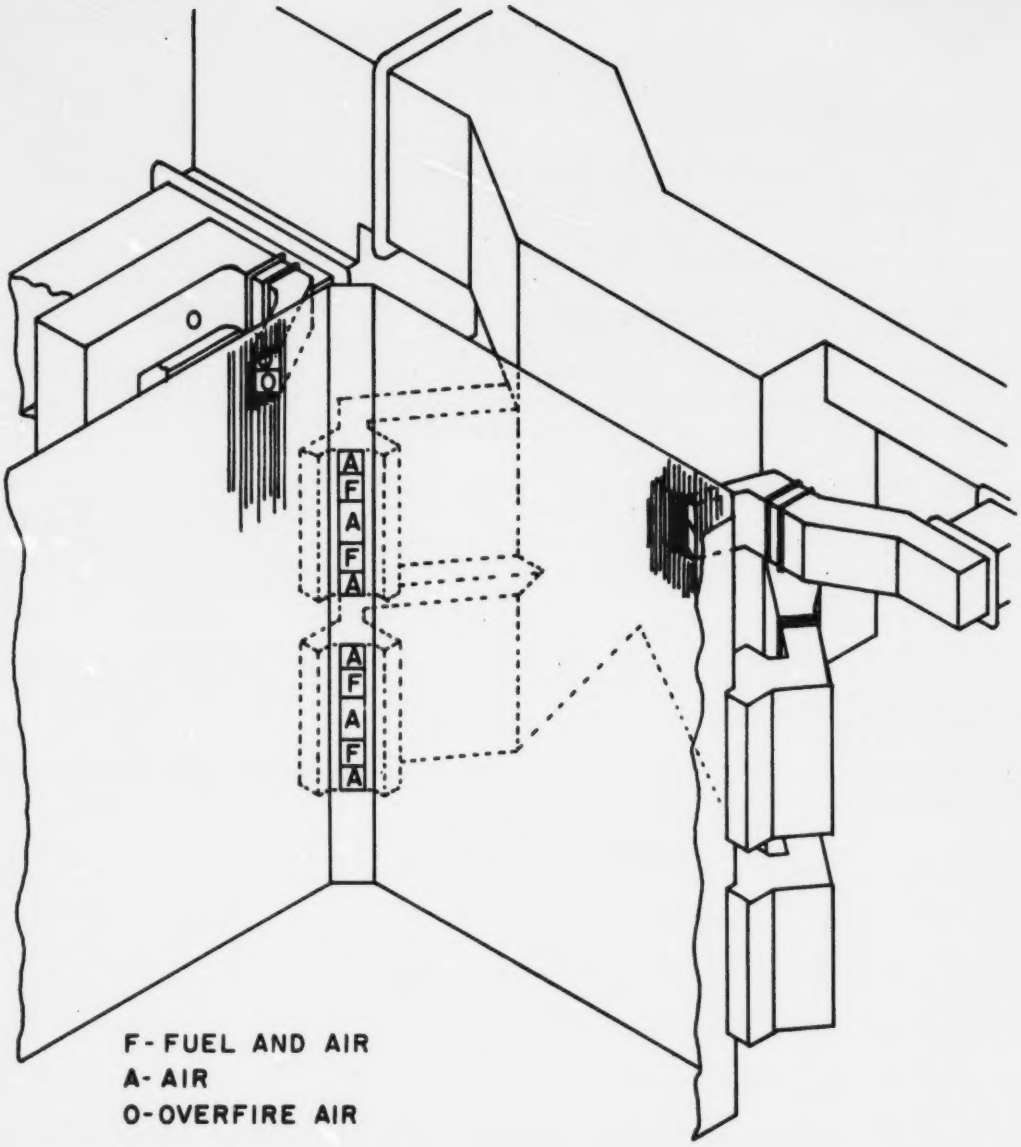


Figure 67. Schematic overfire air system, Barry Station No. 2

DISCUSSION

Tasks 1, 2 and 3 were completed essentially as stated in the program Phase II Objectives.

TASK IV & V - BASELINE AND BIASED FIRING TEST PROGRAMS

Test Data Acquisition and Analysis

The flue gas samples for determination of NO_x, O_2, CO, SO_2 and HC emission levels were obtained at each of the two economizer outlet ducts. The emissions monitoring system is shown in Figure 68.

The flue gas samples were drawn from a twenty-four (24) point grid arranged on centroids of equal area in each duct with the exception of the SO_2 sample which was drawn from a single average point using a heated sample line. Fly ash samples for carbon loss analysis and dust loading were obtained at a single point in each duct.

The percent O_2 leaving the air preheaters was also determined using a twenty-four (24) point grid arranged in centroids of equal area for the determination of air preheater leakage and unit efficiency.

The following instrumentation was used in determining the emission concentrations:

1. NO_x: Chemiluminescence Analyzer
2. O_2 : Paramagnetic Analyzer
3. CO : Nondispersive Infrared Analyzer
4. HC : Flame Ionization Analyzer
5. SO_2: Wet Chemistry
6. Carbon Loss & Dust Loading: ASME Particulate Sampling Train

A summary of the NO_x emission test data is tabulated on Data Sheets C1, C2, C3, C4 and C5.

Unit steam and gas side performance was monitored using calibrated thermocouples, pressure gauges, transducers and manometers as required.

Coal samples were obtained during each test for later analysis. The samples were obtained from each feeder and blended to form a composite sample. Fuel analyses, unit steam flow rates, absorption rates, gas and air weights and

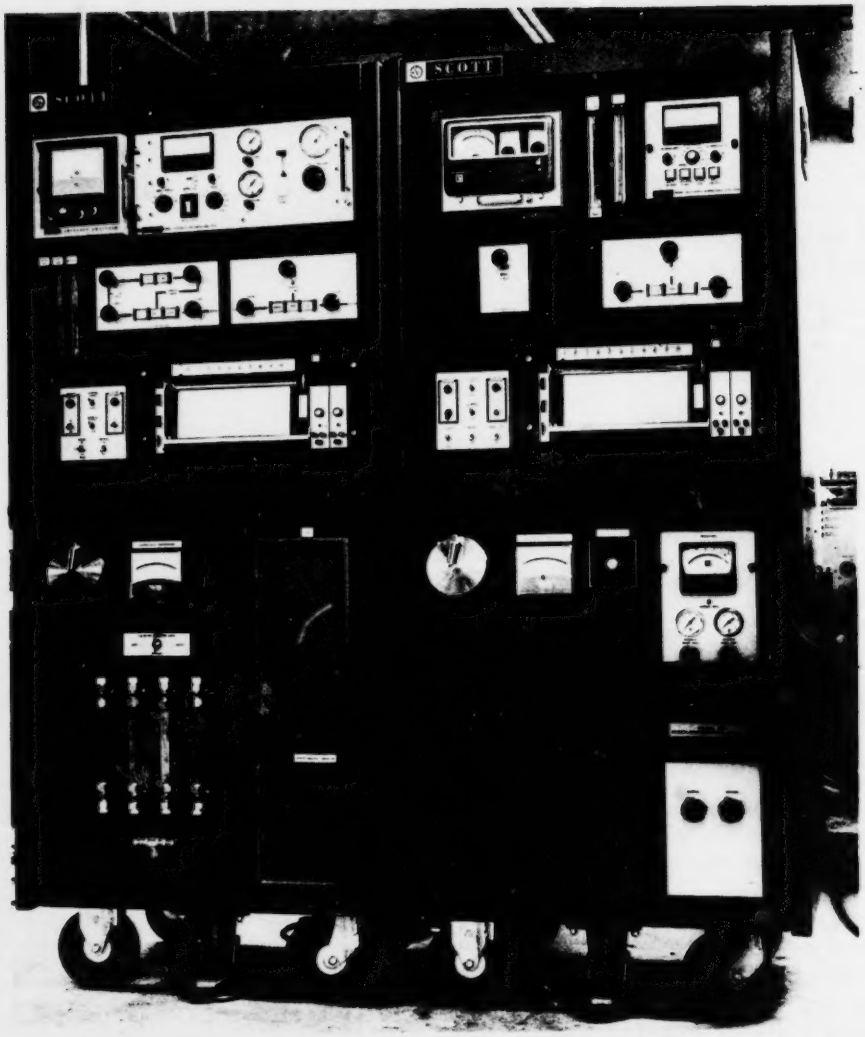


Figure 68. Gaseous emissions test system

efficiencies were calculated for each test run. Unit efficiency was determined using the heat losses method (based on ASME Power Test Code 4.1-1964). The 30 day waterwall corrosion coupon evaluation was conducted using a specially designed probe consisting of four individual coupons. Individual probes were exposed at five locations on the front furnace wall as shown on Figure 69. A typical trace of the control temperature range for each of the twenty coupons is shown on Figure 70. The control temperature ranges were the same for the baseline, biased firing and overfire air studies.

TASK IV - BASELINE TEST STUDY

Load and Excess Air Variation

Tests 1 through 7 were conducted to determine the effect of varying excess air at three unit loads on unit emission levels and performance. These tests were conducted with clean furnace conditions.

As shown in the following table, NO_x emission levels increased with increased excess air but did not change significantly with changes in unit loading. An average increase of 3.34 ng/J was noted for each 1% change in excess air over the normal unit operating range.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Eff. %	WW Slag
1	61	319.3	7.5	35.5	130.6	88.3	Clean
2	62	246.0	43.5	17.5	117.1	88.2	Clean
3	59	362.8	2.5	58.9	151.3	87.6	Clean
4	88	215.0	11.9	12.6	109.2	89.3	Clean
5	112	248.6	9.5	22.7	117.9	89.0	Clean
6	113	181.8	47.3	11.7	107.2	89.1	Clean
7	112	335.1	10.1	30.8	125.3	89.5	Clean

A maximum excess air limit of 30.8 and 58.9 percent was obtained at full and half load conditions respectively due to ID fan capacities.

Minimum excess air limits of 20 to 25 percent were determined as those at which acceptable CO emission levels could be maintained. Reduction of NO_2 emission levels using excess air reduction was therefore limited to approximately 248.6 ng/J as obtained during Test 5.

The changes in NO_2, CO, percent carbon loss in the fly ash and unit efficiency versus theoretical air to the fuel firing zone are shown on Figures 71, 72, 73 and 74, respectively. The theoretical air (TA) to the firing zone is used in this case as it accounts for variations in position and leakage in the compartment dampers above the top active fuel compartment and thereby presents a more accurate determination of the actual air available for combustion in the fuel firing zone than does the total excess air. As seen on Figure 71 for clean furnace conditions the NO_2 correlates well with TA with little variation due to unit load. As shown on Figures 72 and 73 carbon loss in the fly ash and CO emission levels increased with decreased TA levels. Unit load does not appear to have a discernable effect. Figure 74 is a plot of unit efficiency versus

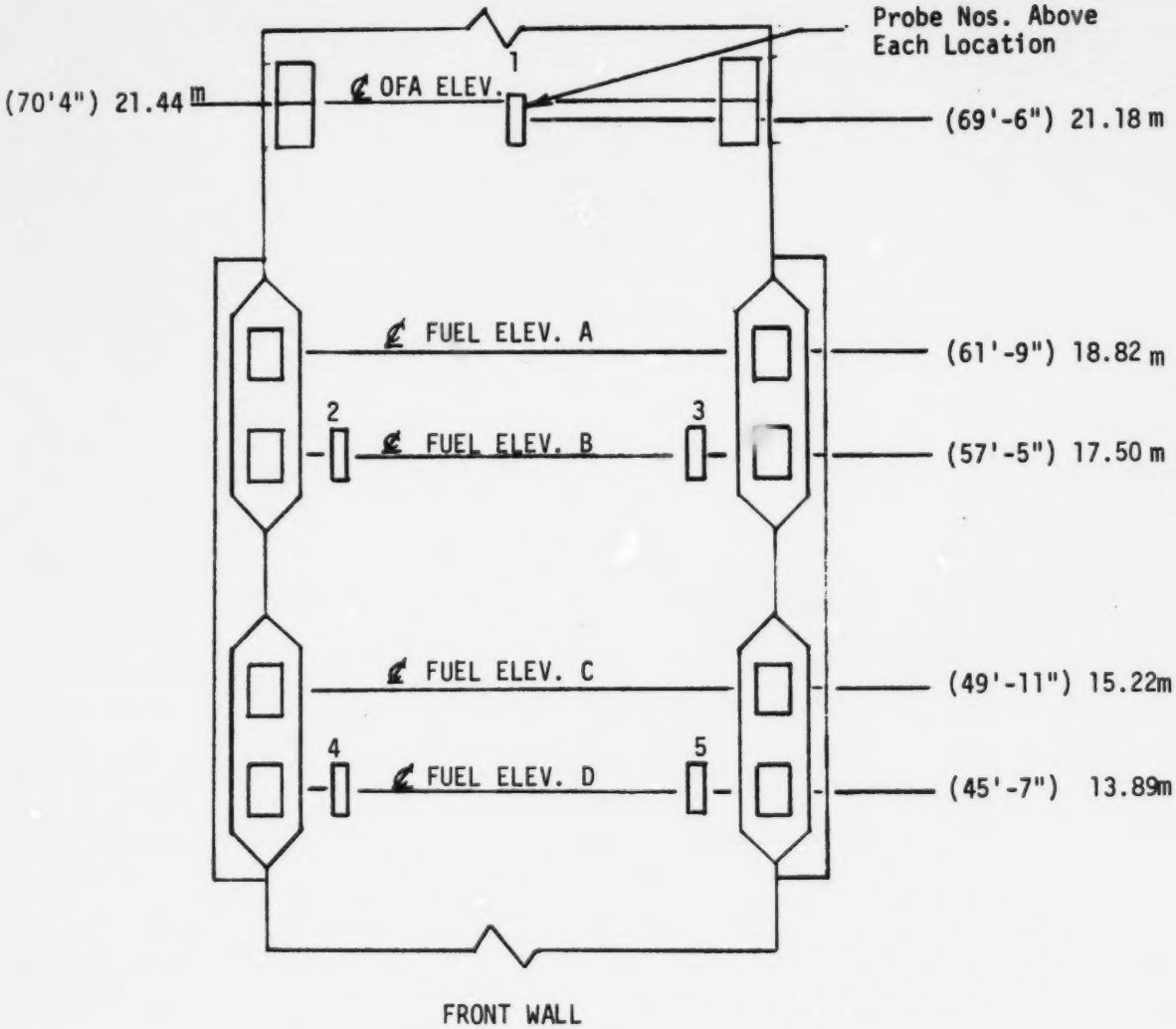


Figure 69. Waterwall corrosion probe locations, Alabama Power Company Barry Station No. 2

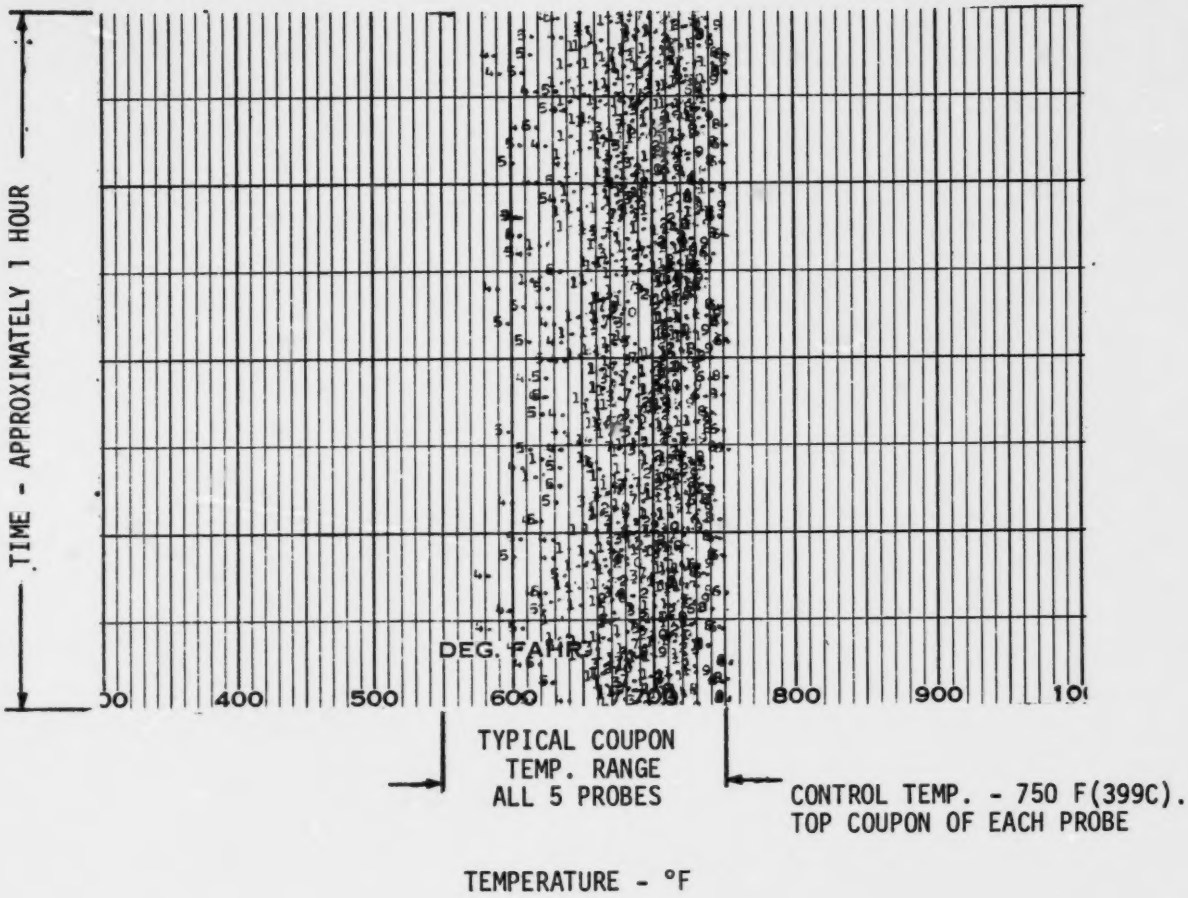


Figure 70: Typical corrosion probe temperature range, Barry Station No. 2

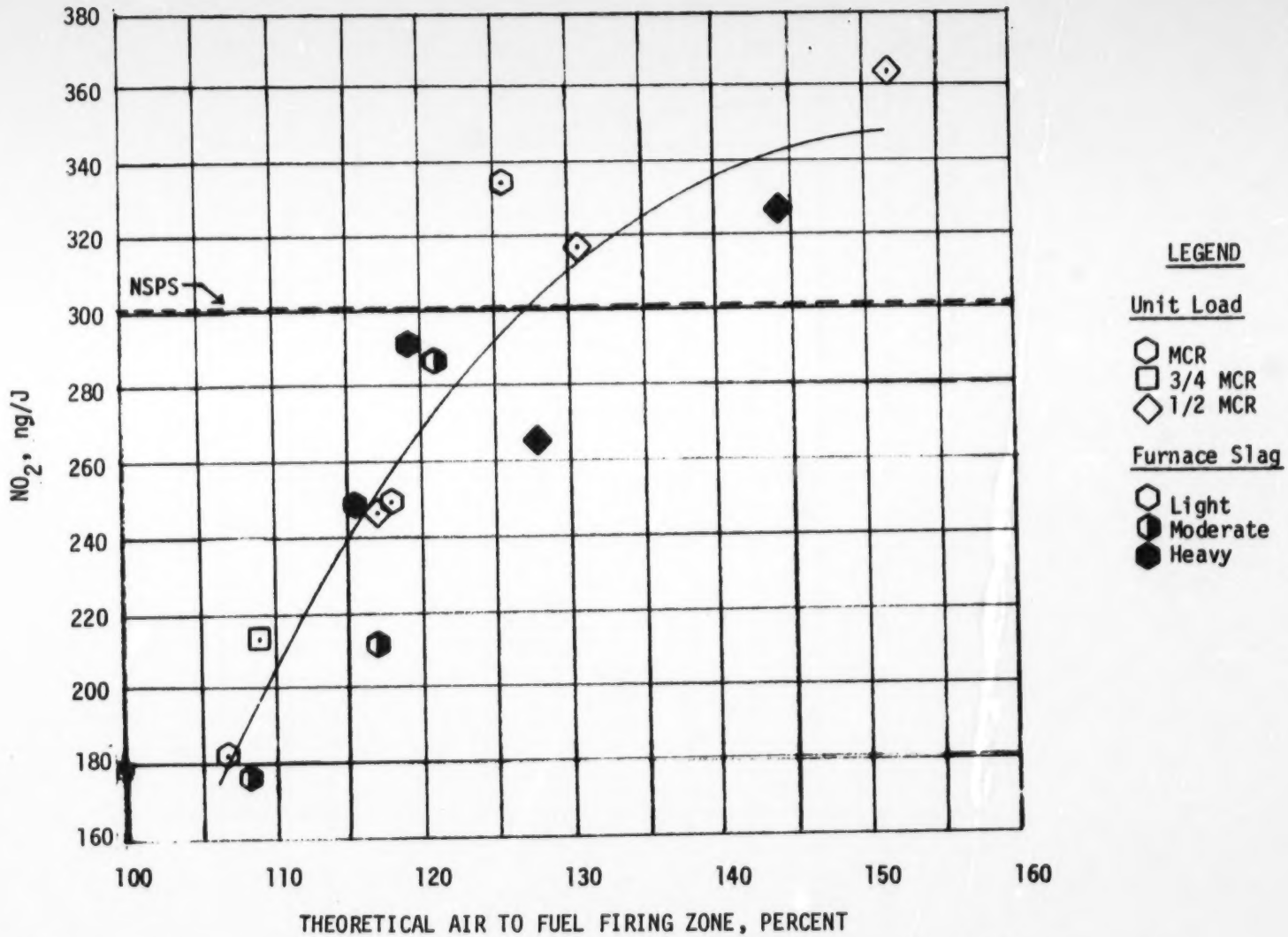


Figure 71: NO_2 vs. theoretical air to fuel firing zone, baseline study, Tests 1-14

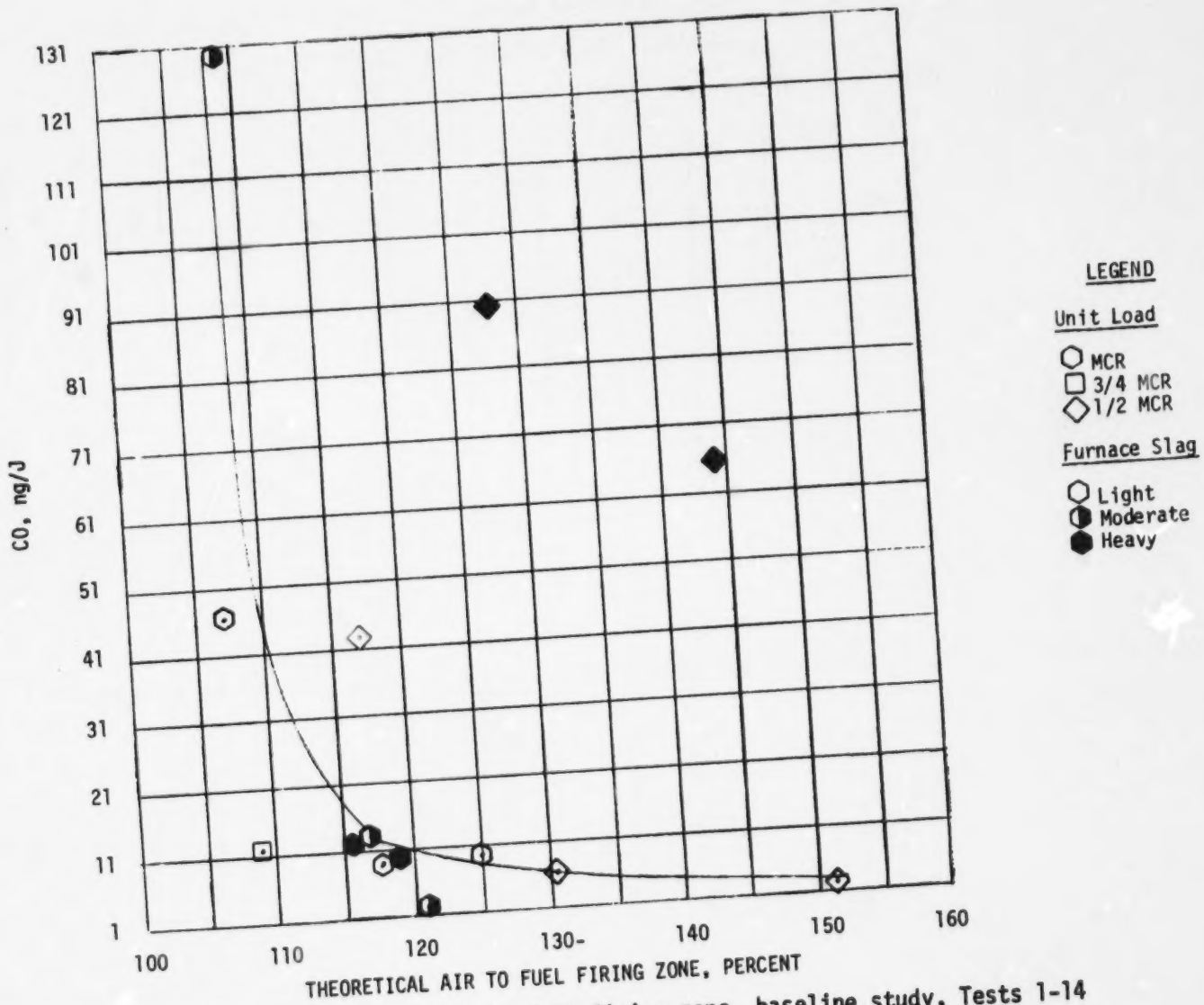


Figure 72: CO vs. theoretical air to fuel firing zone, baseline study, Tests 1-14

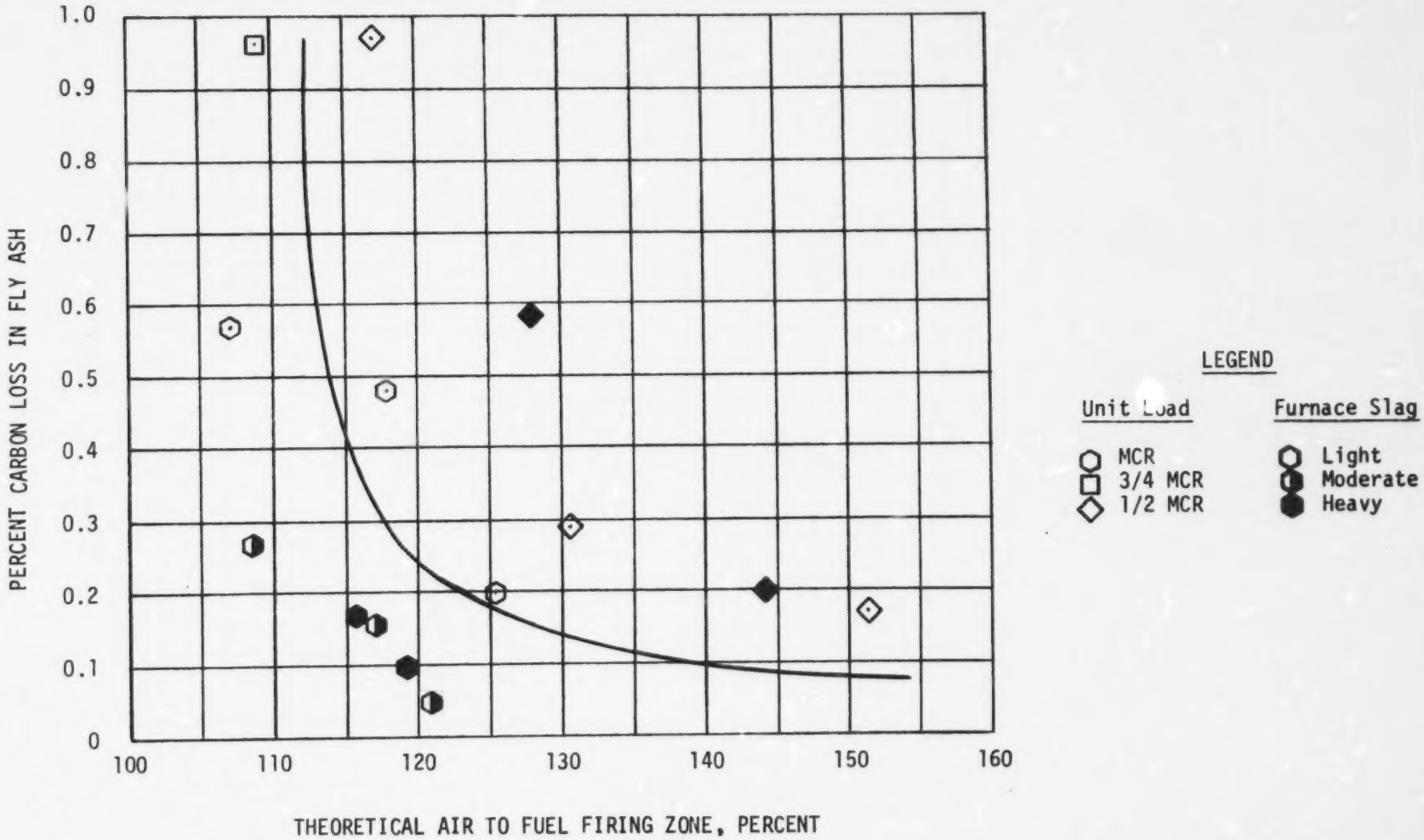


Figure 73: Percent carbon loss vs. theoretical air to fuel firing zone, baseline study, Tests 1-14

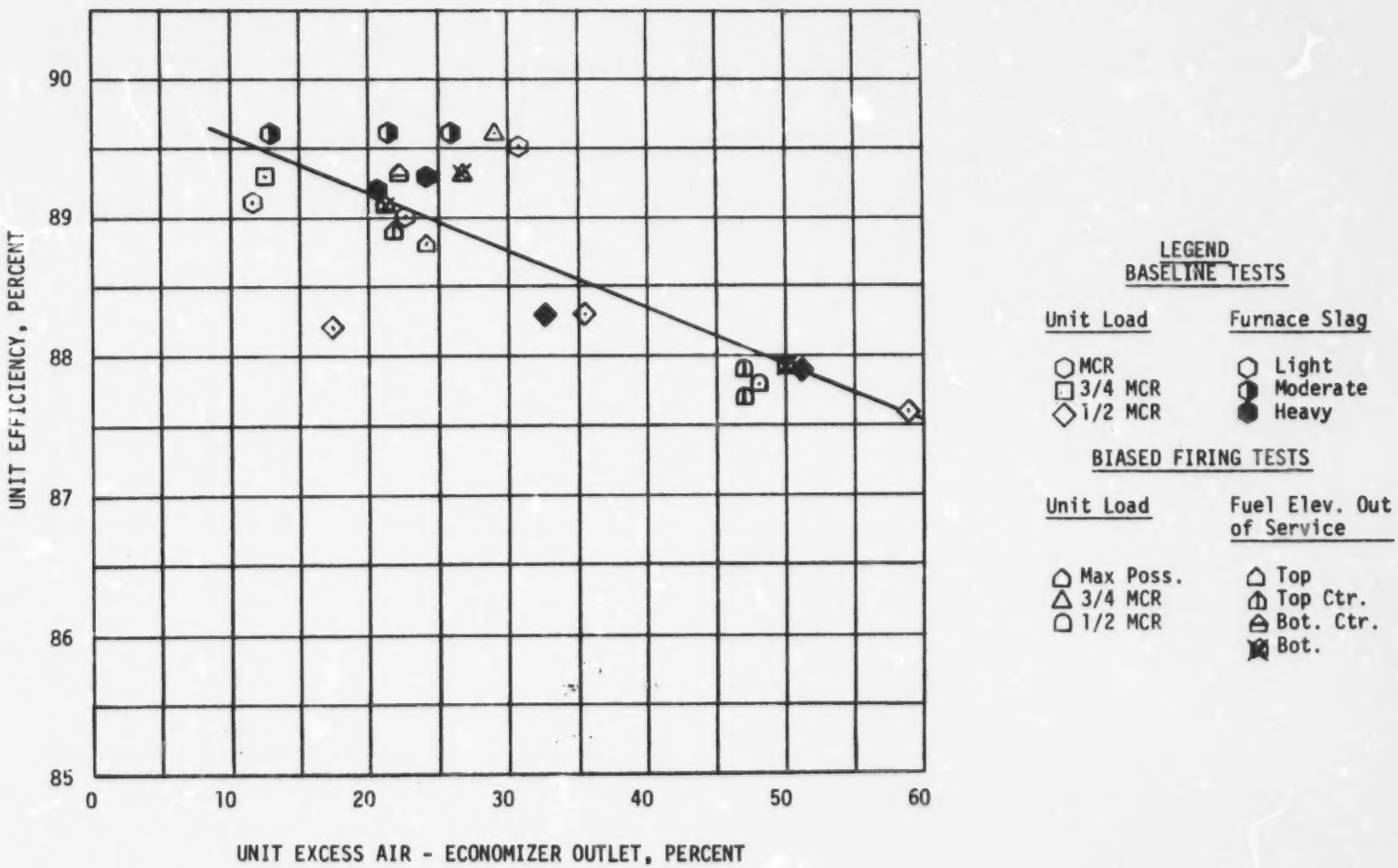


Figure 74: Unit efficiency vs. unit excess air

unit excess air measured at the economizer outlet.

During this portion of the test program total hydrocarbon levels (HC) were monitored and were found to be present in only trace quantities as shown on Data Sheets C1 and C2. The SO_2 levels measured are also shown on Data Sheets C1 and C2.

Furnace Wall Deposit Variation

Tests 8 through 14 were conducted to determine the effect on unit performance and emission levels of varying furnace waterwall deposits from a clean condition to the maximum possible slagging condition obtainable. The maximum slagging condition was obtained after operation in excess of twenty-four hours without operating any wall blowers. During this time period slag deposits of up to 102 mm in thickness could be obtained in and above the fuel firing zone.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Eff. %	WW Slag
8	114	213.5	14.1	21.5	116.9	89.6	1/2 Max Dep
9	112	178.7	130.2	13.0	108.5	89.6	1/2 Max Dep
10	112	286.1	1.6	26.0	120.8	89.6	1/2 Max Dep
11	59	267.0	90.3	32.7	128.0	88.3	Max Dep
12	57	327.2	66.9	51.2	144.1	87.9	Max Dep
13	114	247.7	12.4	20.7	115.7	89.2	Max Dep
14	113	292.6	10.3	24.3	119.2	89.3	Max Dep

As can be seen from Figure 71, furnace slagging did not exhibit a discernable effect on NO_x emission levels. As shown in Figures 72 and 73, this condition was also found to be true for carbon loss in the fly ash and CO emission levels with the exception of the half load Tests 11 and 12 where CO levels higher than those obtained with clean furnace conditions were observed. The high CO levels may have been due to slag buildup at or near the fuel and air nozzles which could have contributed to poor combustion. The higher CO levels were not observed under full load with heavy slag operation. Figure 74 indicates that furnace cleanliness did not exhibit any discernable effect on unit efficiency.

Slag patterns taken during clean, moderate and heavy slagging conditions at full load operation are shown on Figures 75, 76 and 77.

TASK V - BIASED FIRING STUDY

Fuel Elevations Out of Service Variation

Tests 15 through 24 were conducted to determine the effect on NO_x emission levels of taking various fuel elevations out of service (biased firing) at various unit loadings. As shown on the following table the maximum NO_x emissions control was obtained with the top elevation of fuel nozzles out of service at maximum and 75 percent maximum loading (Tests 20 and 21). At 50 percent maximum loading (Test 23) the high excess air levels required to maintain unit steam temperatures appeared to negate any NO_x reductions obtained by biasing the top

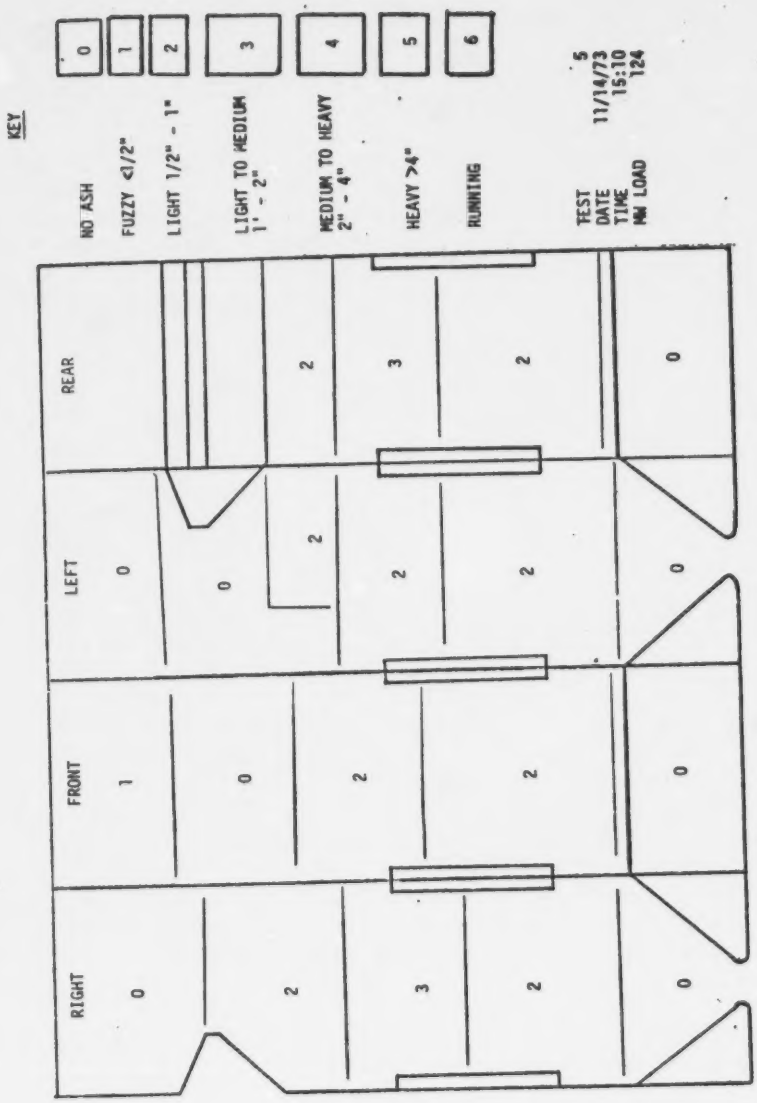


Figure 75: Furnace slag pattern, clean furnace

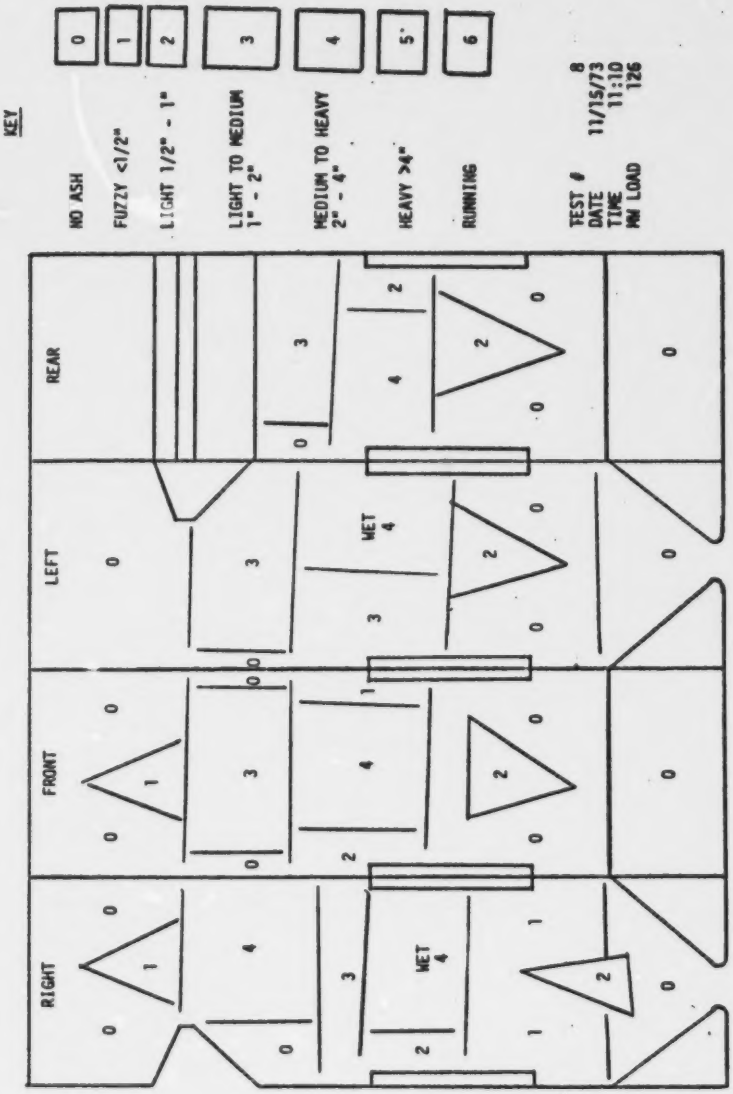


Figure 76: Furnace slag pattern, moderate slag furnace

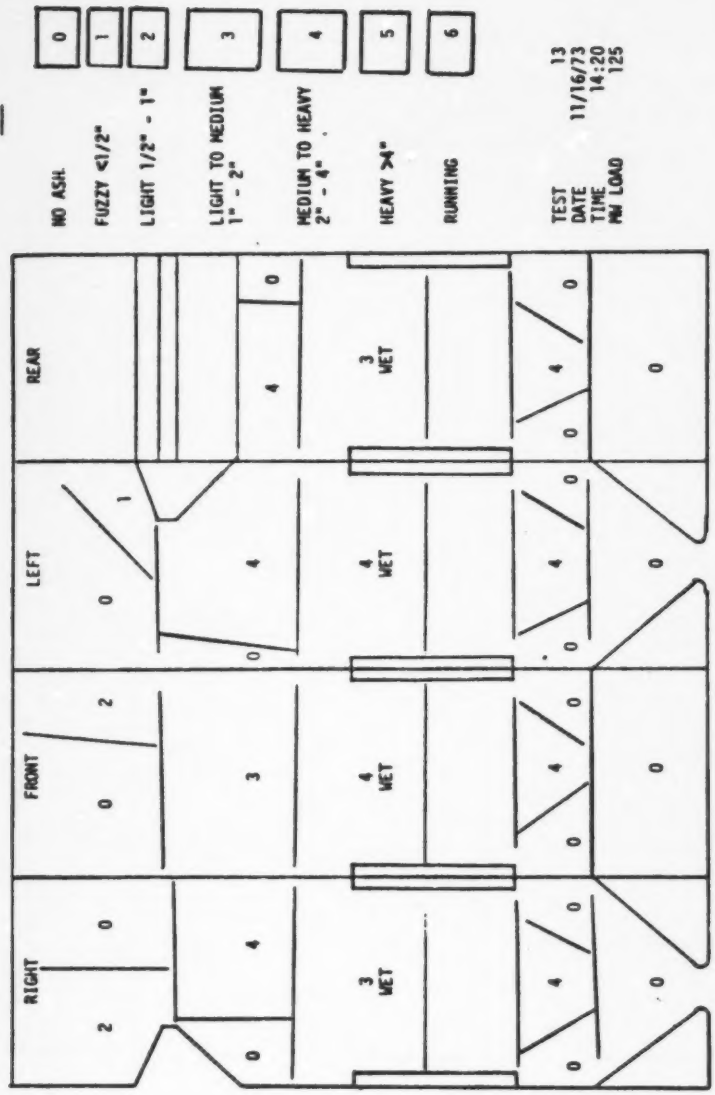


Figure 77: Furnace slag pattern, heavy slag furnace

fuel nozzle elevation, however, the emissions level obtained was below the current EPA limit for coal fired units of 301 ng/J.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Eff. %	Fuel Nozzle Elevation Out of Service
15	55	288.0	9.8	50.1	105.8	87.9	Bottom
16	82	272.8	8.9	26.7	121.7	89.3	Bottom
17	87	200.6	14.0	21.1	116.5	89.1	Bottom
18	89	189.2	11.9	22.2	117.5	89.3	Bottom Center
19	89	189.9	10.6	21.8	117.2	88.9	Top Center
20	87	143.1	8.1	24.2	94.7	88.8	Top
21	86	166.2	9.5	29.0	97.3	89.6	Top
22	58	268.5	9.1	48.0	112.5	87.8	Top
23	59	249.1	7.0	47.0	141.4	87.9	Top Center
24	56	306.2	8.4	47.0	141.3	87.7	Bottom Center

As can be seen from Figure 78, biasing the center two and bottom fuel elevations did not have a discernable effect on NO_x emission levels although the emission level tended to be higher at reduced unit loadings for given TA levels.

Figures 79 and 80 indicate that with biased firing, low TA levels to the fuel firing zone were obtained without increasing either CO emission levels or the carbon loss in the fly ash. Figure 74 shows that biased firing operation did not significantly affect unit efficiency. This condition is due to the ability to maintain acceptable total unit excess air levels during biased firing operation.

TASK VIII - UNIT OPTIMIZATION STUDY

Load and Excess Air Variation (After Modification)

Tests 1 through 7 were performed with unit conditions closely approximating those of Baseline Tests 1-7 under Program Task IV. A clean furnace was maintained as the excess air was varied at three unit loads.

The effect of these operating conditions emission levels and performance can be seen in the Table below.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	WW Slag
1	61	221.9	8.4	33.5	127.1	88.4	Clean
2	59	167.4	114.4	16.0	113.4	88.8	Clean
3	60	319.8	10.6	64.7	155.4	87.4	Clean
4	87	162.4	33.4	15.5	111.0	89.8	Clean
5	125	202.1	8.0	21.0	115.3	89.4	Clean
6	122	165.3	38.8	12.4	107.1	89.2	Clean
7	117	238.8	6.6	25.4	119.5	89.5	Clean

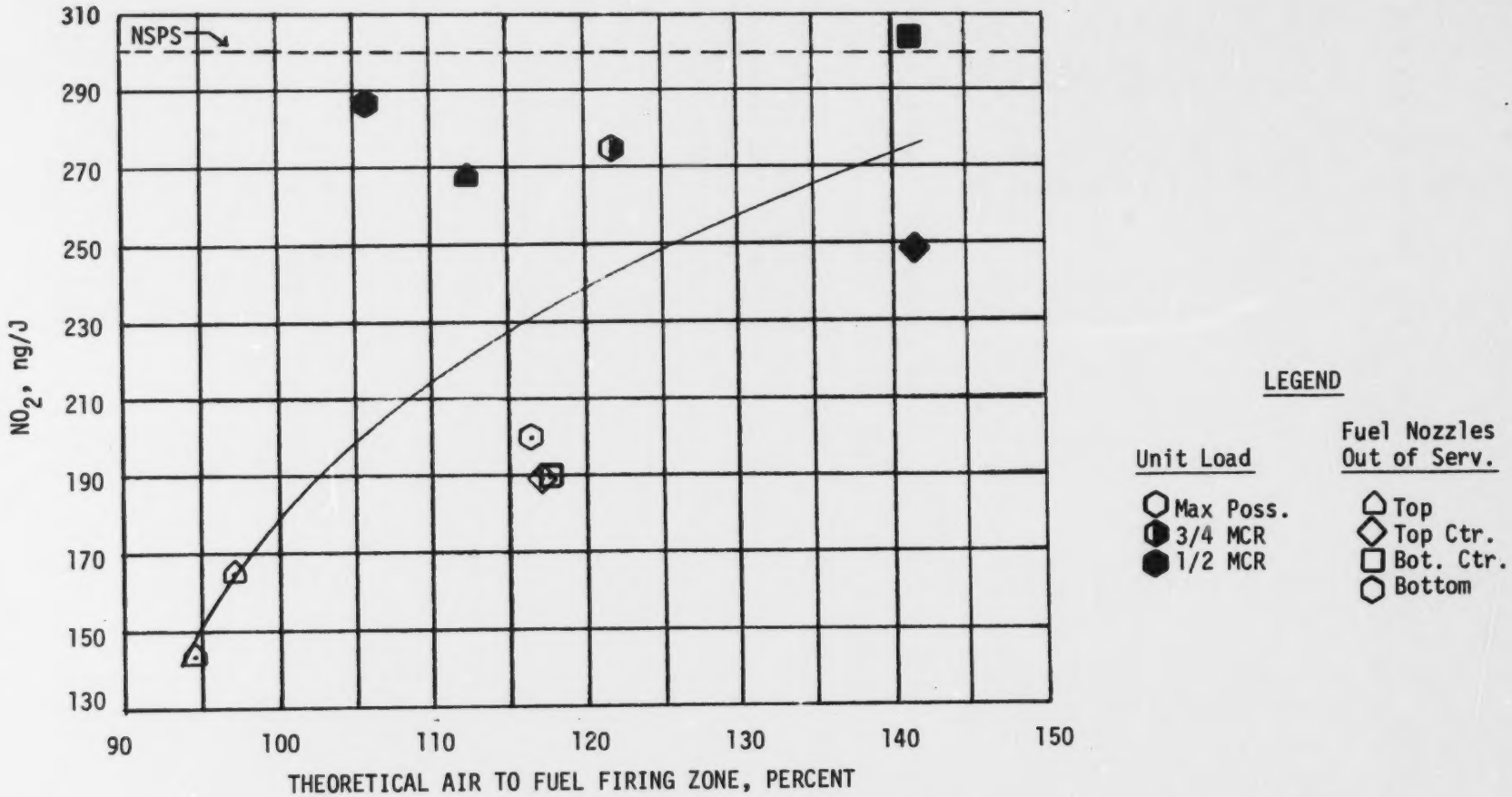


Figure 78: NO_2 vs. theoretical air to fuel firing zone, biased firing study, Tests 15-24

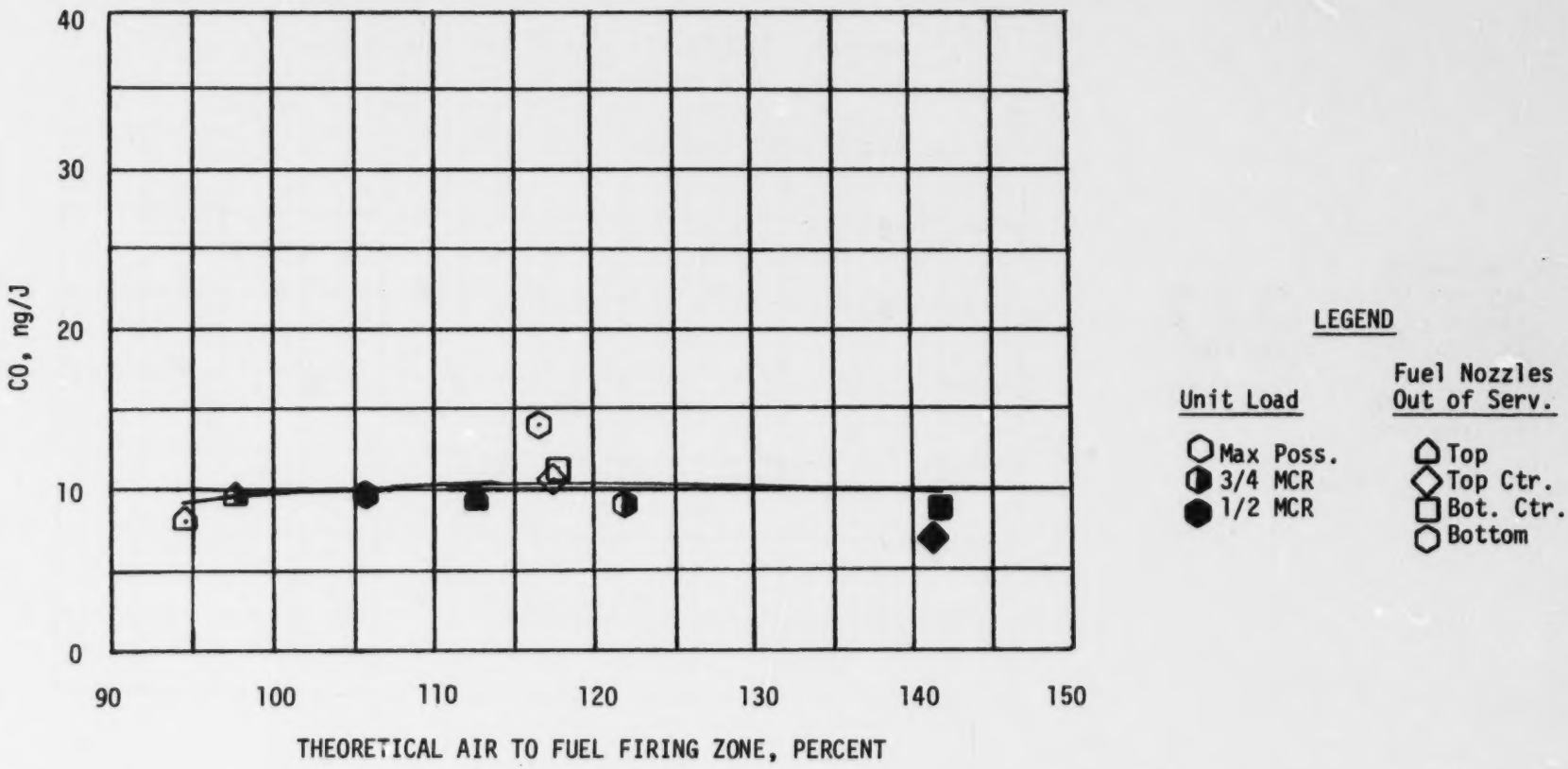


Figure 79: CO vs. theoretical air to fuel firing zone, biased firing study, Tests 15-24

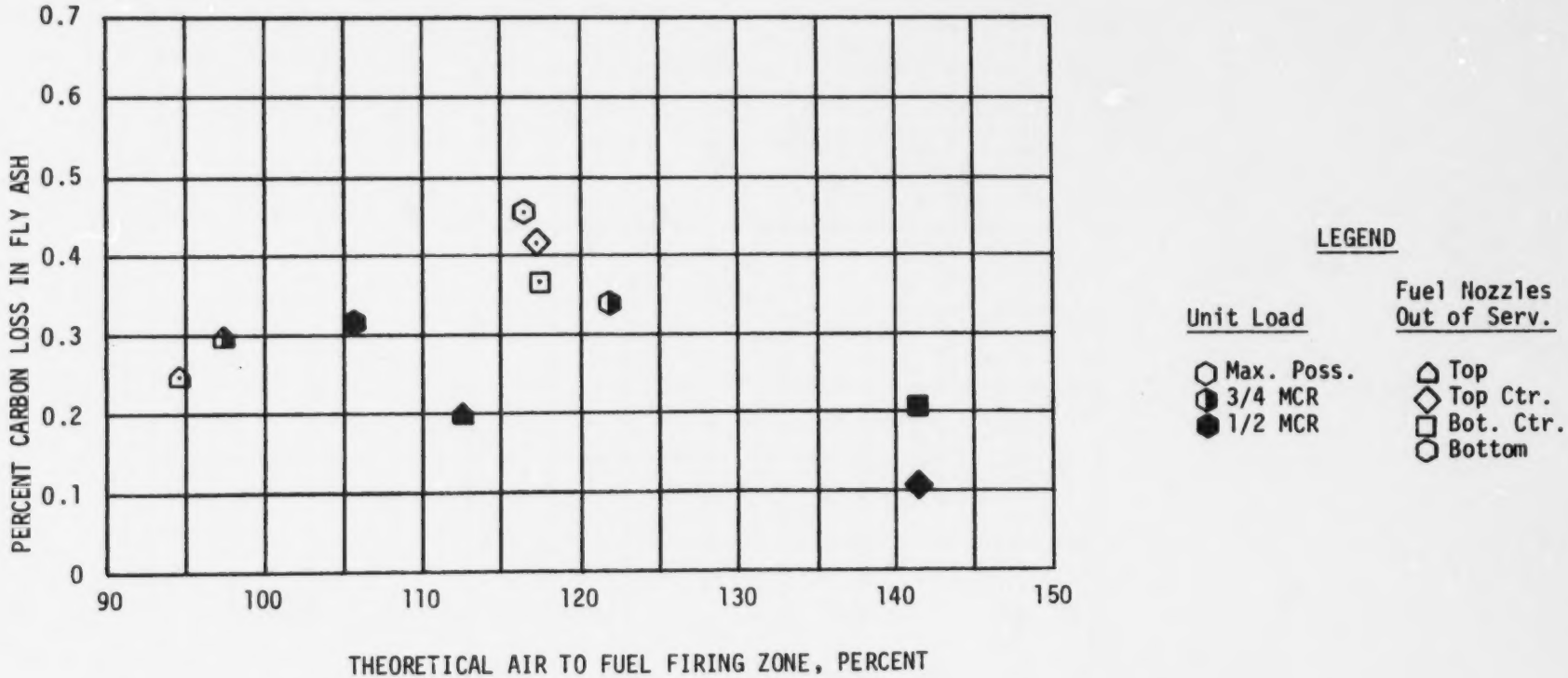


Figure 80: Percent carbon loss vs. theoretical air to fuel firing zone, biased firing study, Tests 15-24

As witnessed in the previous baseline tests, NO_x emission levels increased with increased excess air.*

ID fan capacities limited excess air to a maximum of 64.7 and 33.5 percent at half and full load conditions respectively. Acceptable minimum excess air limits were established at 20-25 percent to control CO emission levels. Thus, NO_x emission levels could only be reduced to approximately 215 ng/J through excess air reduction. The effect of theoretical air to the firing zone on NO_x, CO, and percent carbon loss in the fly ash (% CL) can be seen in Figures 81, 82 and 83. Consistent with the original baseline tests, theoretical air to the firing zone (TA) was used for comparison in place of total excess air (EA). TA is determined by location and means of admission as well as quantity, and consequently better defines that air actually available for initial combustion.

Figure 81 indicates a definite increase in NO_x emission levels with increasing TA for clean furnace conditions. CO emission levels and percent carbon loss in the fly ash can be seen to increase with decreased TA without overfire air. Reasonable control of CO and % CL can only be maintained at TA levels above 120%. No definite relationship can be observed between unit load and CO emission levels. Percent CL can be seen to be greater at higher unit loads for given TA levels.

Changes in steam generator efficiency versus excess air at the economizer outlet are presented in Figure 84. Overall, unit efficiency decreases as the excess air increases.

Hydrocarbon emission levels appeared only in trace quantities for this portion of the test program. HC and SO_2 levels are presented on Data Sheet C3.

Furnace Wall Deposit Variation (After Modification)

The effect of furnace waterwall deposits on unit performance and emission levels was studied in Tests 8 through 14 (Clean Condition - Maximum Slagging Conditions). The results are shown in the table below. Dirty conditions were established after a minimum of 24 hours of not operating the wall blowers. Deposits of up to 102 millimeters in thickness could subsequently be found in and above the fuel firing zone.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	WW Slag
8	122	235.3	7.4	17.8	112.3	89.0	1/2 Max
9	124	166.9	9.6	12.1	106.9	88.9	1/2 Max
10	119	215.4	9.2	26.6	120.5	89.5	1/2 Max

* In general, NO_2 values were slightly lower after modification for the same test conditions. This resulted from an upgraded firing system installed between the sets of tests along with an average percent nitrogen in fuel decrease of 0.15 percent (1.21 to 1.06 percent). Also, fuel higher heating values and furnace outlet temperatures tended to be lower for Tests 1-7 after modification.

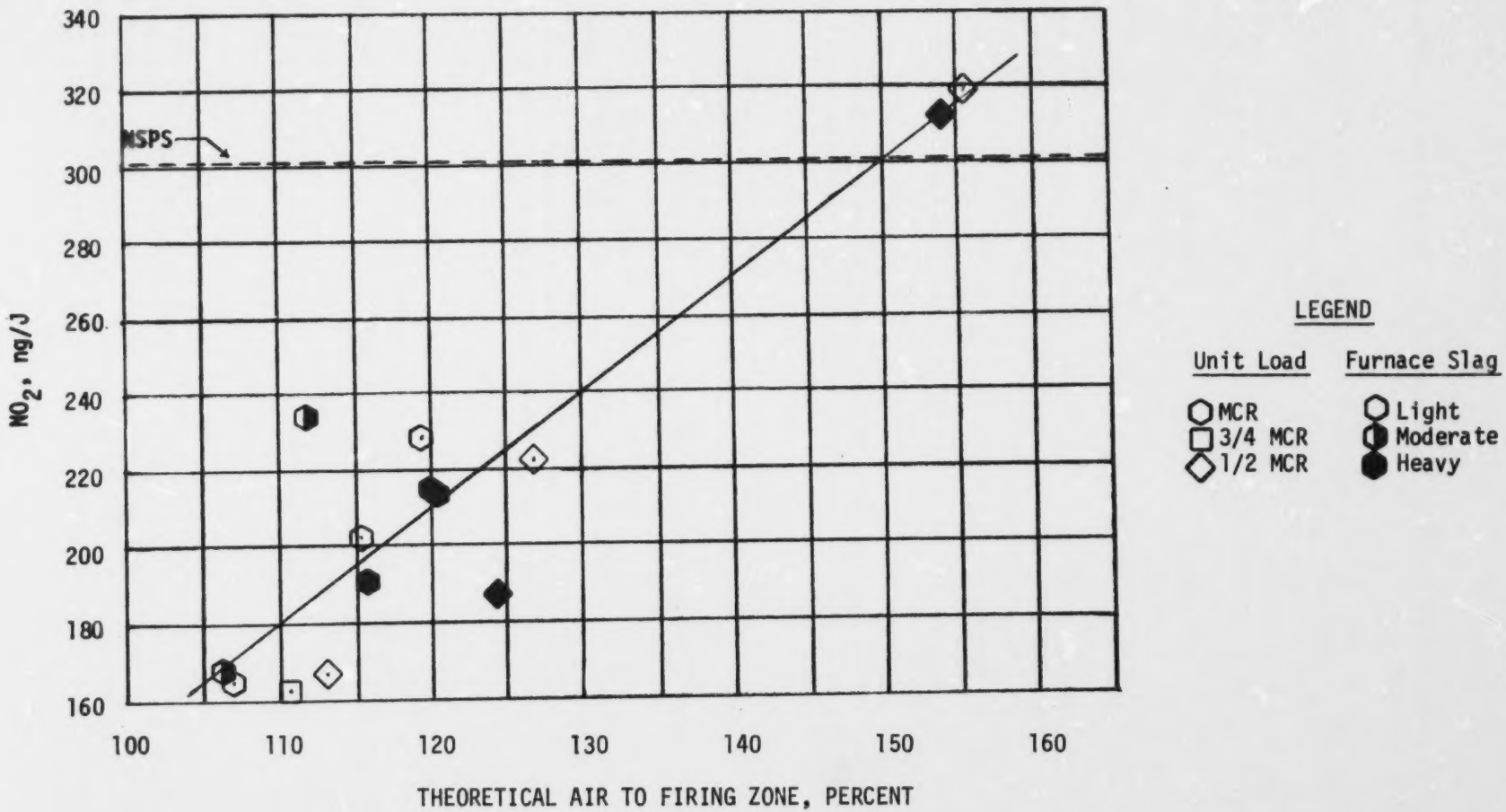


Figure 81: NO_2 vs. theoretical air to firing zone, overfire air study, load and excess air variation, Tests 1-14

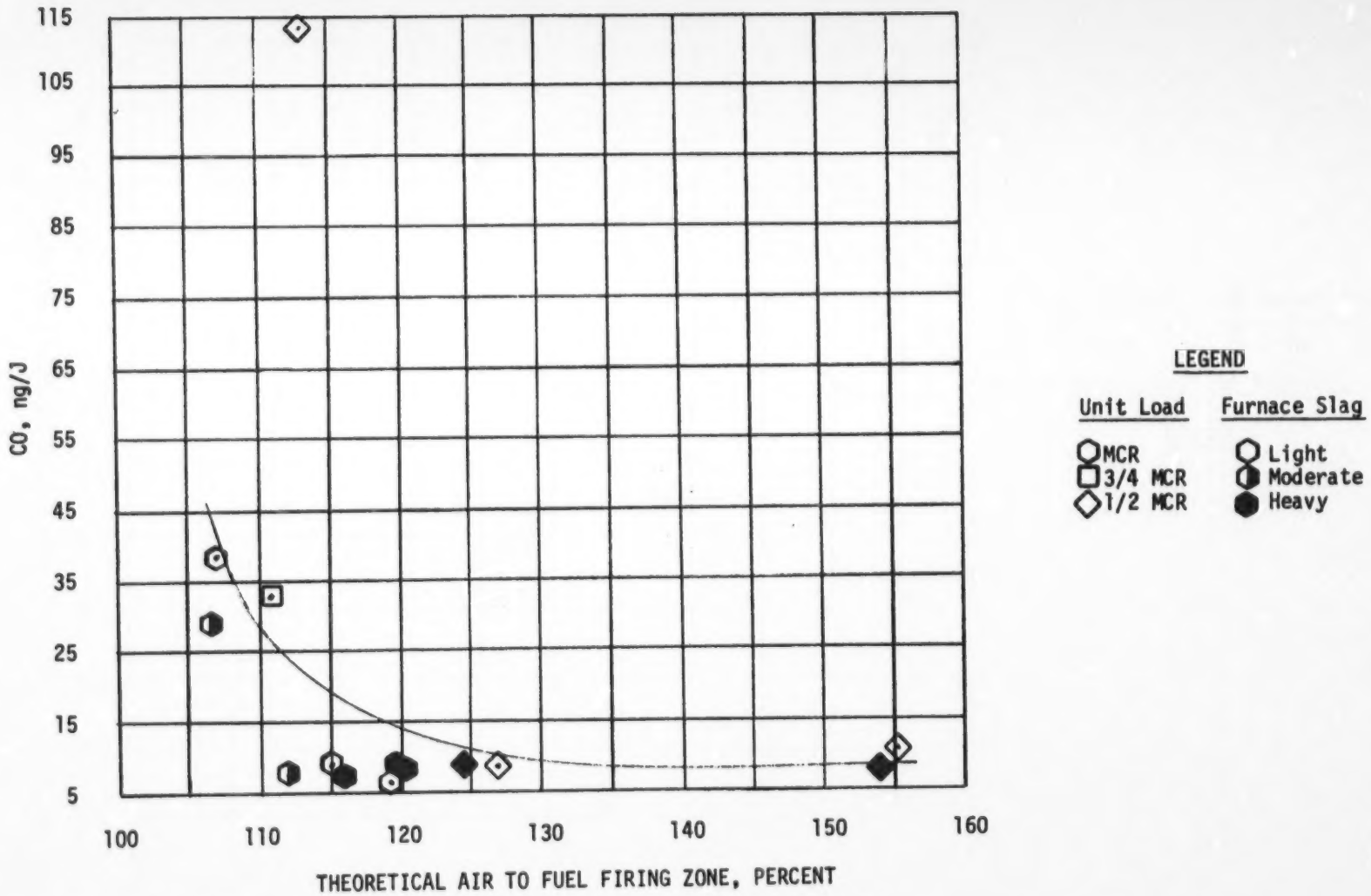


Figure 82: CO vs. theoretical air to firing zone, overfire air study, load and excess air variation, Tests 1-14

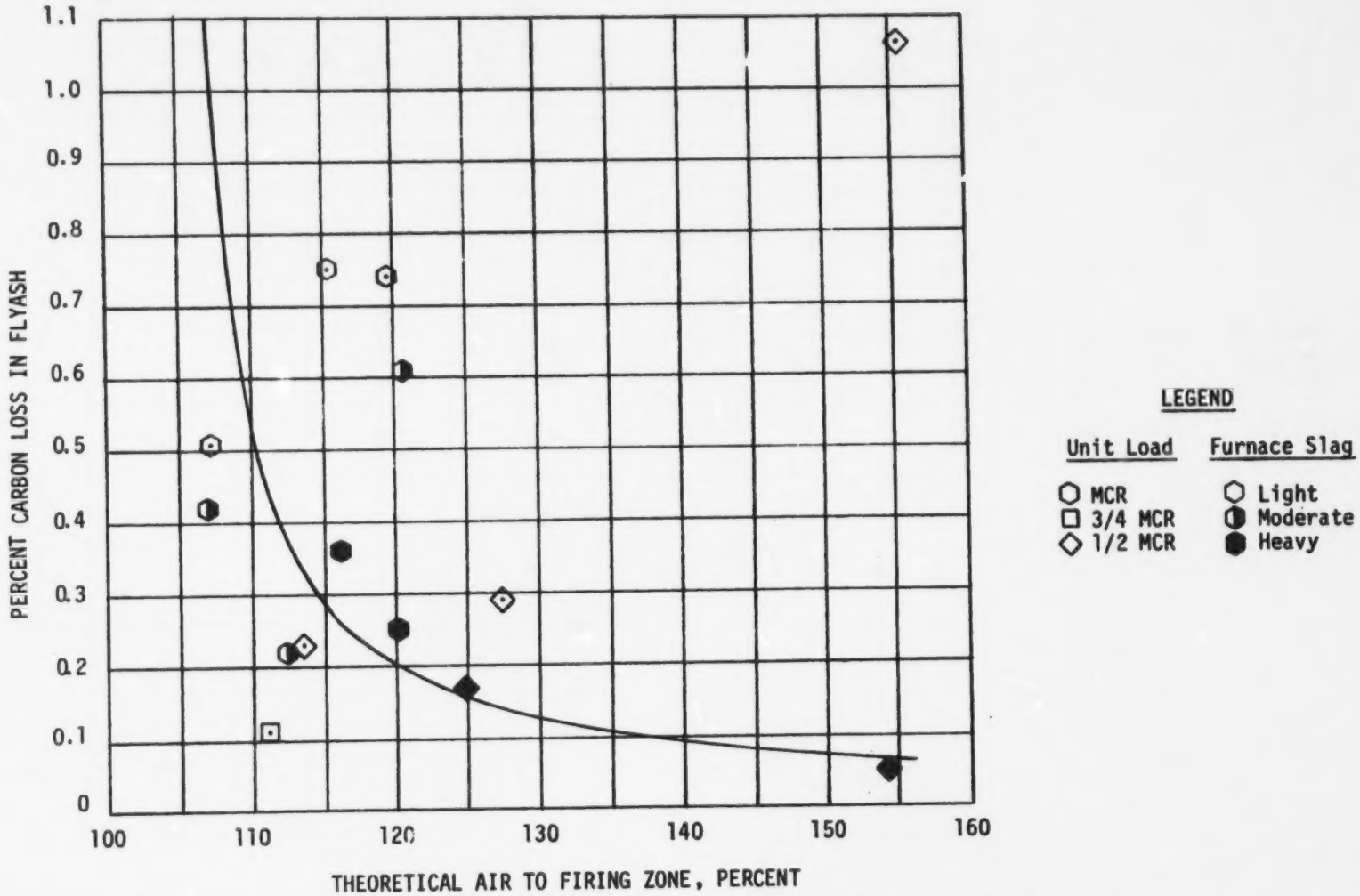


Figure 83: Percent carbon loss vs. theoretical air to firing zone, overfire air study load and excess air variation, Tests 1-14

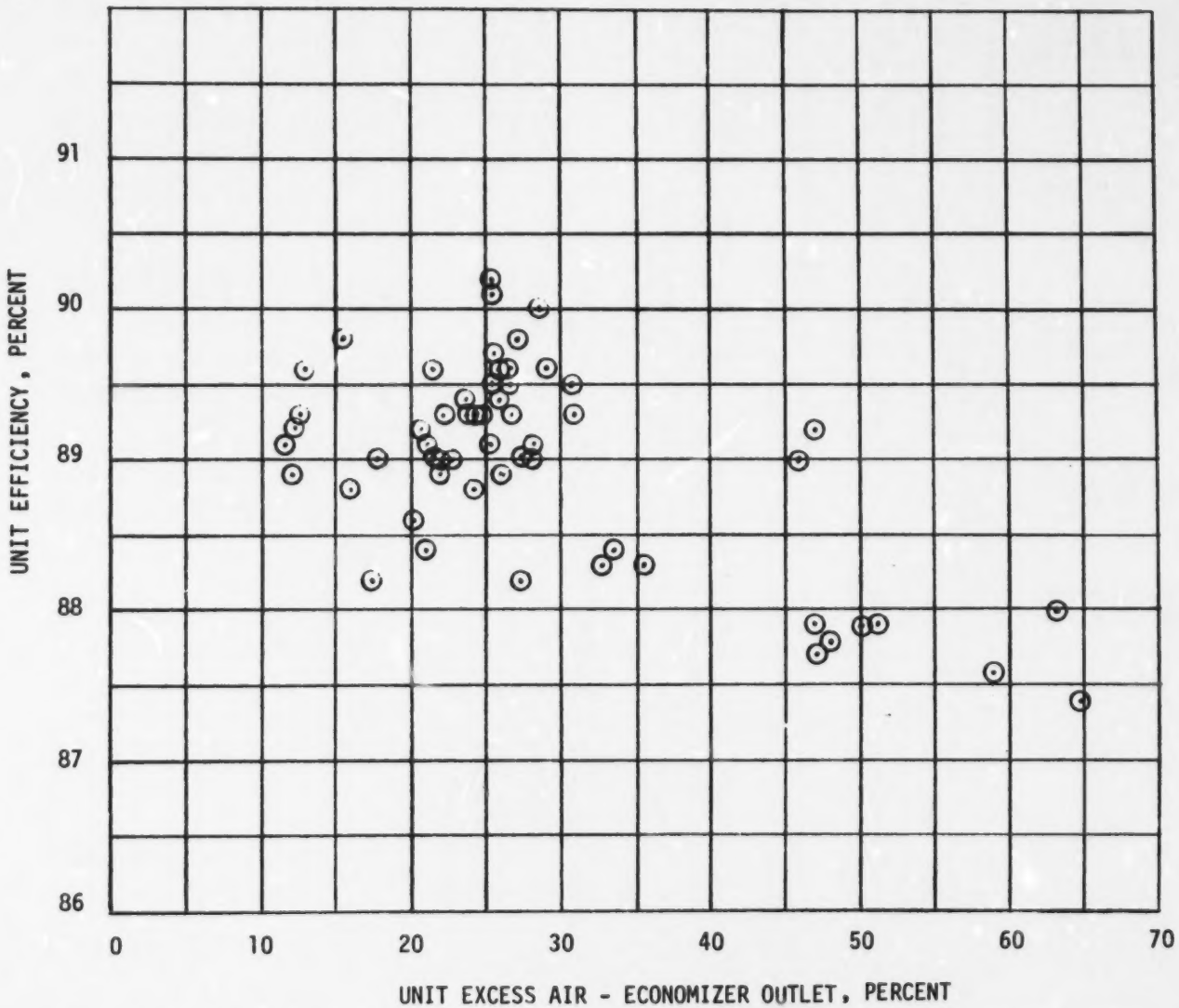


Figure 84: Unit efficiency vs. excess air - economizer outlet, all tests (before & after modification)

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	WW Slag
11	68	186.8	8.0	30.9	124.6	89.3	Max
12	61	312.9	7.3	63.1	154.0	88.0	Max
13	120	195.6	7.1	22.0	116.2	89.0	Max
14	118	215.4	7.0	25.9	119.9	89.4	Max

Figures 81, 82 and 83 reveal no observable effect of furnace cleanliness on NO_x or CO emission levels along with percent carbon loss in the fly ash. Again, NO_x values were generally slightly lower after modification. Nitrogen in fuel decreased an average of 0.19 percent from 1.23 percent. Furnace outlet temperatures were somewhat lower for Tests 8 through 14 after modification although fuel higher heating values showed no definite change.

Slag patterns taken during full load operation for clean, moderate and heavy slagging furnace conditions are shown in Figures 85, 86 and 87.

This set of tests also confirms the results found in Tests 1 through 7, i.e., NO_x emission levels increase with increased excess air. NO_x cannot be decreased through excess air reductions below 20 percent excess air while maintaining an acceptable CO emission level without overfire air.

OFA Location, Rate and Velocity Variation

Tests 15 through 23 were performed to establish the effect of overfire air admission on NO_x emission levels. The unit load and excess air remained constant for moderately dirty furnace conditions. Location of air admission to the furnace was varied.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	Theo. Air To Firing Zone - %	Unit Eff. %	Mills In Serv.	Adm. Pts.*	Adm. Rate
15	93	178.7	8.6	114.5	90.0	BCD	0-1	0
16	94	127.3	9.1	96.7	89.8	BCD	0-1	Max
17	94	127.3	9.9	95.8	89.7	BCD	0-2	Max
18	96	114.4	14.6	84.8	89.6	BCD	0-1,0-2	Max
19	94	116.1	11.9	89.3	89.3	BCD	0-1,0-2	1/2 Max
20	96	161.7	8.8	100.5	90.2	BCD	0-3	Max
21	95	241.7	7.7	117.4	90.1	ABC	0-1	0
22	95	164.6	7.8	90.4	89.0	ABC	0-1,0-2	Max
23	96	168.1	7.7	96.9	89.1	ABC	0-1,0-2	1/2 Max

* OFA Admission Points:

0-1: Top overfire air compartment
0-2: Bottom overfire air compartment.
0-3: Top fuel elevation out of service.

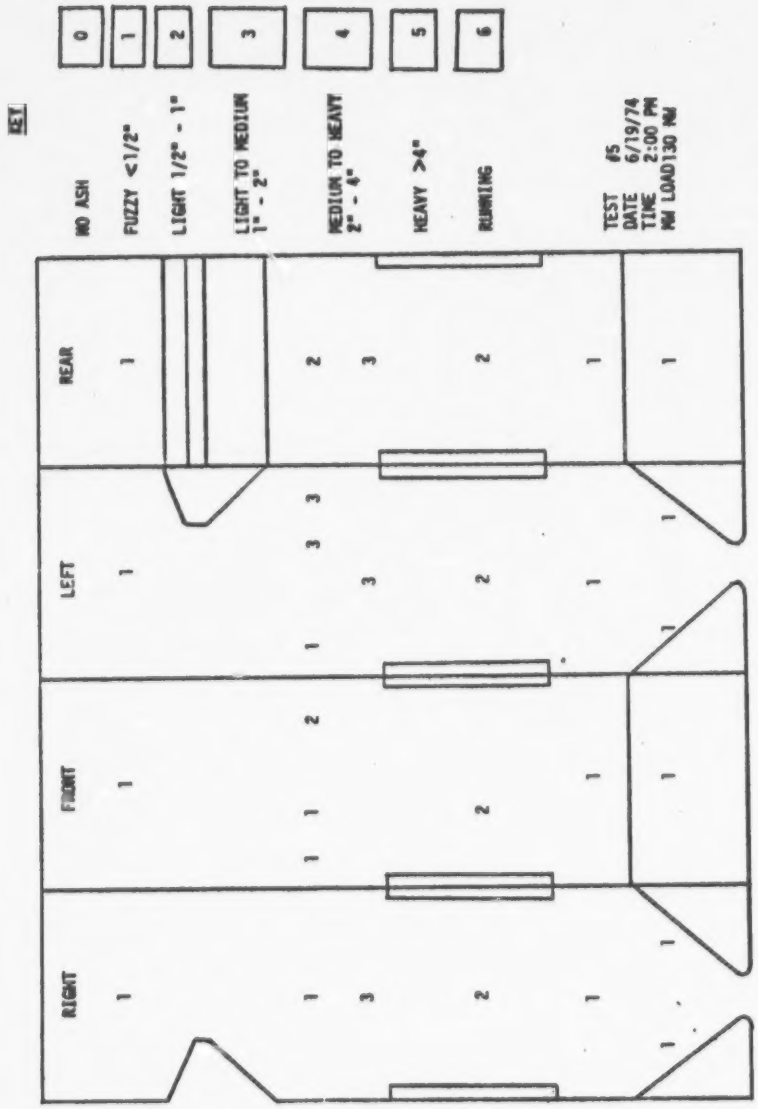


Figure 85: Furnace slag pattern, clean furnace

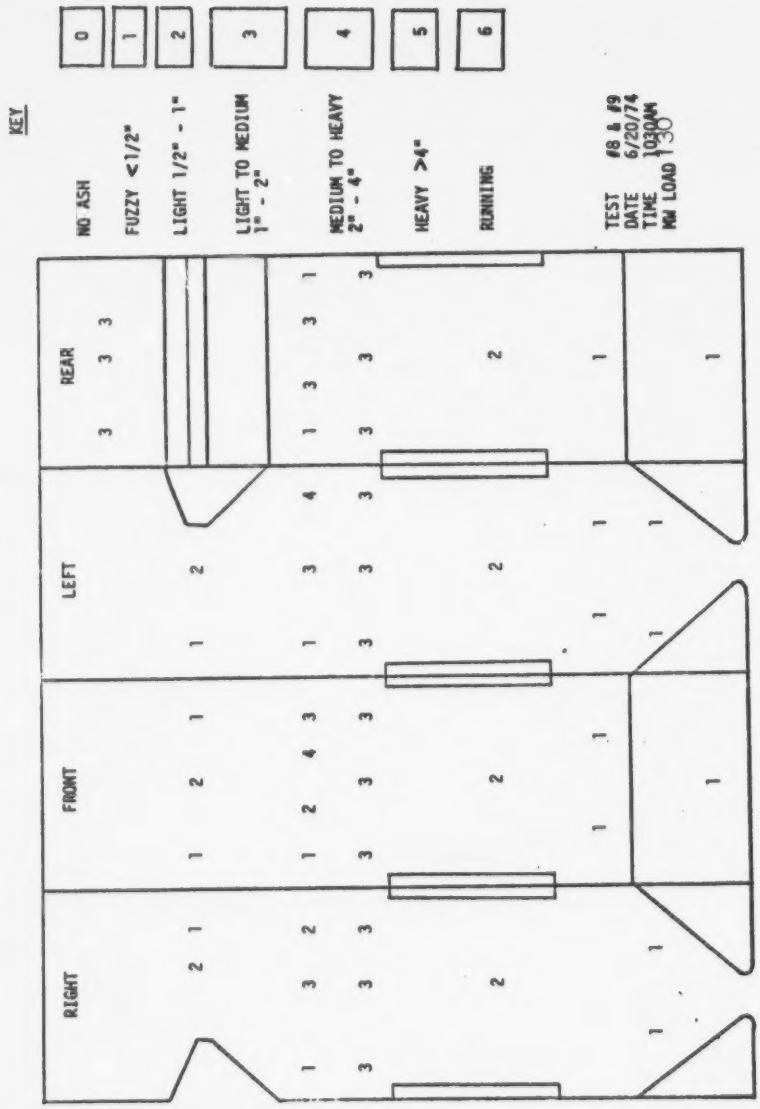


Figure 86: Furnace slag pattern, moderate slag furnace

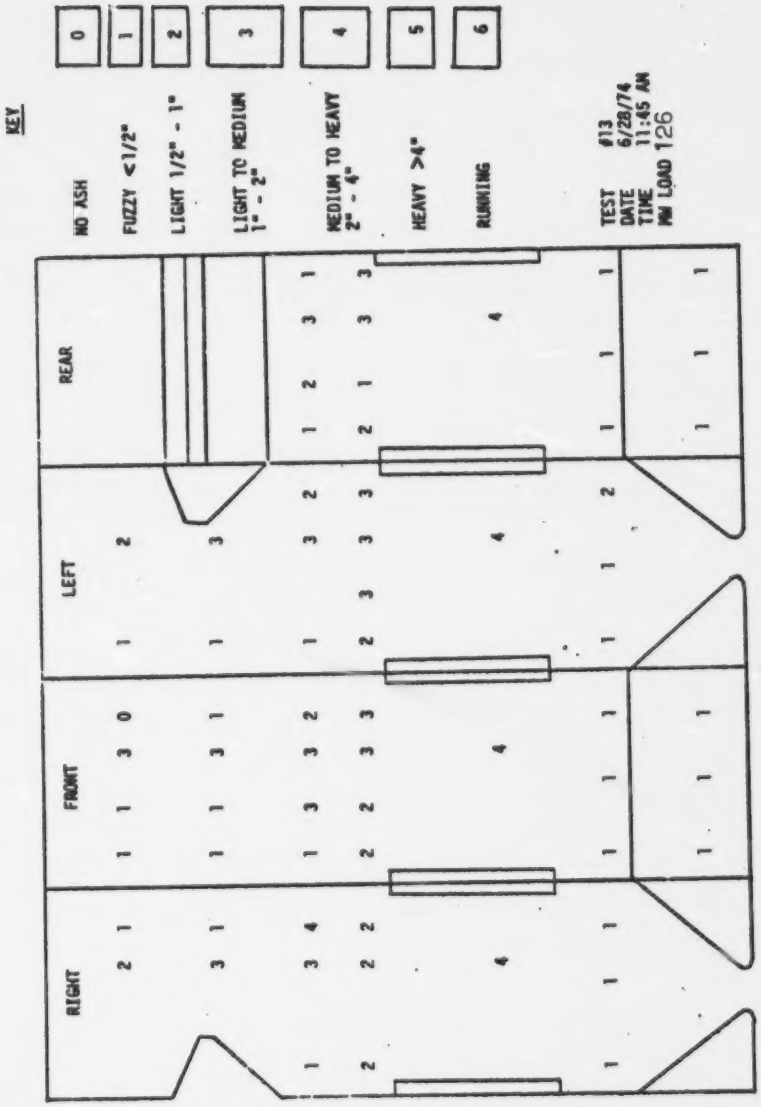


Figure 87: Furnace slag pattern, heavy slag furnace

As shown in Figure 88, this set of tests shows a tendency of NO_x emission levels to decrease with decreased theoretical air to the firing zone. NO_x levels are generally higher with ABC mills (top 3 elevations) in service than with BCD mills (bottom 3 elevations). Both operating conditions support the premise of reducing NO_x emission levels by reducing the air input to the fuel firing zone and admitting the balance of combustion air downstream of that point. The fire is thereby spread out over more of the furnace reducing its intensity. The above factors are limited by flame stability which became very lazy in Test 18. By using the bottom 3 elevations in place of the top 3 elevations, the distance between the overfire air and the firing zone was increased. (The mean firing elevation is also slightly decreased.) Comparison of Tests 18 and 19 with Tests 22 and 23 reveals lower NO_x levels obtained with increased distance between the overfire air and the firing zone. Operation at TA levels below 95% did not result in significant reductions in NO_x emission levels.

CO emission levels remained acceptable for the entire set of tests where the total excess air was approximately 27 percent as shown on Figure 89.

OFA admission location or rate variation exhibited no significant change in percent carbon loss in the fly ash as shown on Figure 90.

Unit efficiencies were not significantly affected by fuel elevations in service, or by overfire air location and rate variation. This is explained by the fact that essentially constant total excess air levels were maintained during this study.

OFA Tilt Variation

Tests 24 through 30, and 33, were conducted at full unit load with excess air and theoretical air levels to the firing zone of approximately 24 percent and 92 percent, respectively. With moderate slagging conditions on the waterwalls the fuel nozzle tilts and OFA tilts were varied. This essentially moves the firing zone both in the furnace and in its relative position to the overfire air. Fuel nozzle tilts that are maximum minus combined with OFA tilts of maximum plus increase the distance between the overfire air and the firing zone. As with previous methods of increasing this distance, the NO_x emission levels are decreased. Figure 91 shows that as the tilts are moved toward one another (fuel nozzle tilts up; OFA tilts down), the OFA-firing zone separation is decreased and the NO_x levels are increased.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	Fuel Nozzle Tilt-°	OFA Tilts-°
24	113	169.6	7.7	25.9	94.2	89.6	-5	0
25	116	145.4	8.3	23.7	92.4	89.3	-23	0
26	114	183.9	9.7	25.1	93.2	88.9	+19	0
27	113	172.2	6.7	22.3	91.5	89.3	-5	-30
28	115	202.1	8.6	20.2	89.6	88.6	+22	-30
29	116	142.3	15.0	23.7	92.6	89.4	-21	+30
30	116	169.6	7.9	21.6	90.7	89.0	-4	0
33	114	166.5	7.5	27.4	94.6	89.0	-22	-22

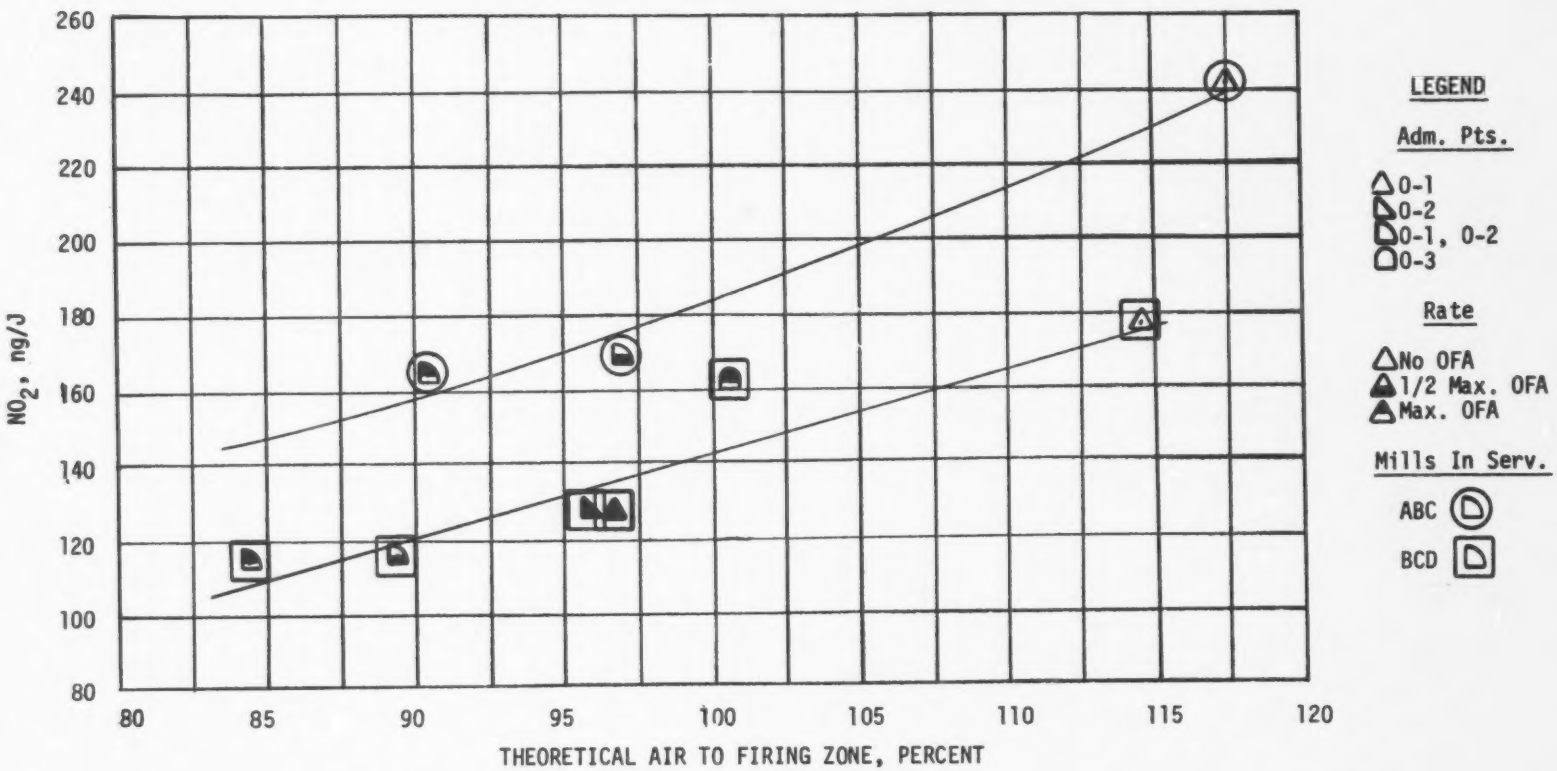


Figure 88: NO_2 vs. theoretical air to firing zone, overfire air location, rate & velocity variation, Tests 15-23

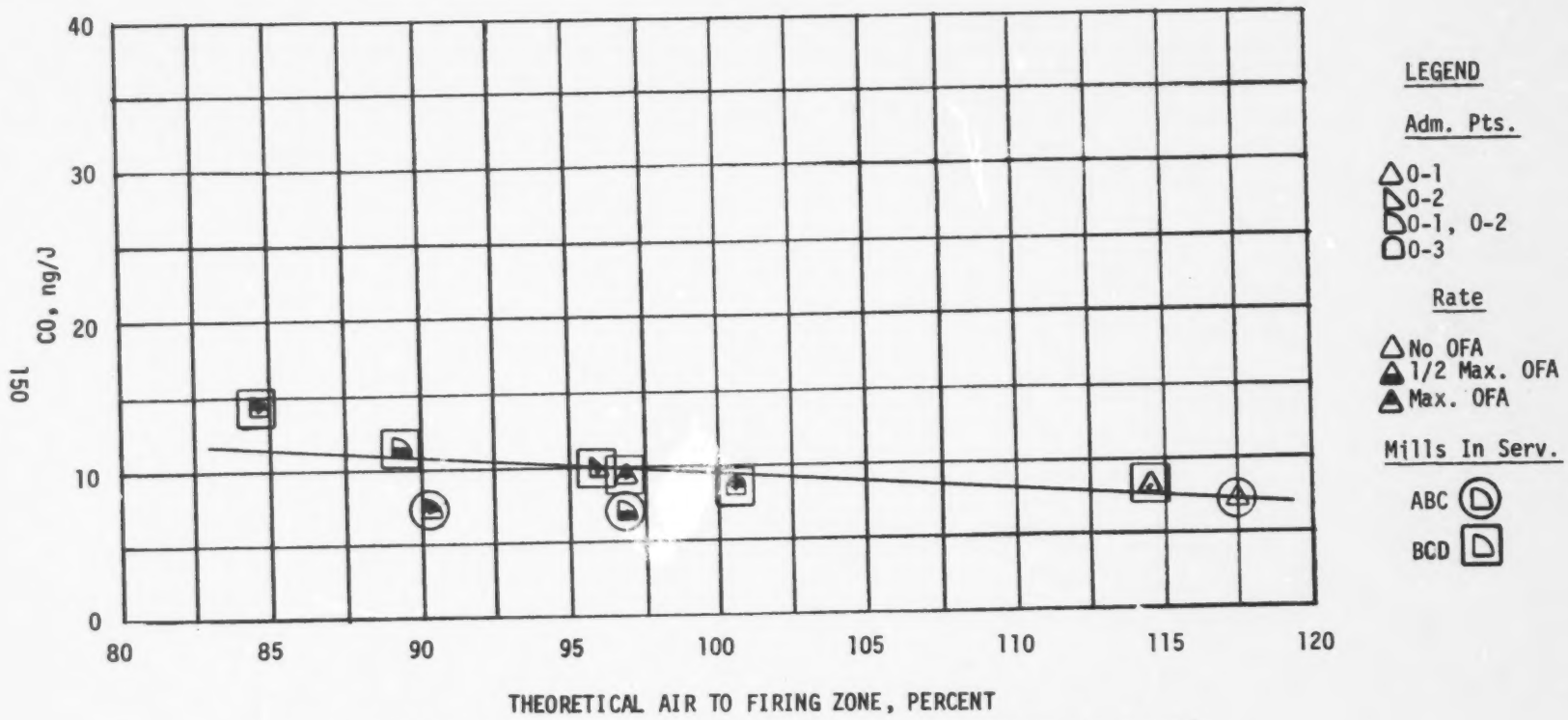


Figure 89: CO vs. theoretical air to firing zone, overfire air location, rate & velocity variation, Tests 15-23

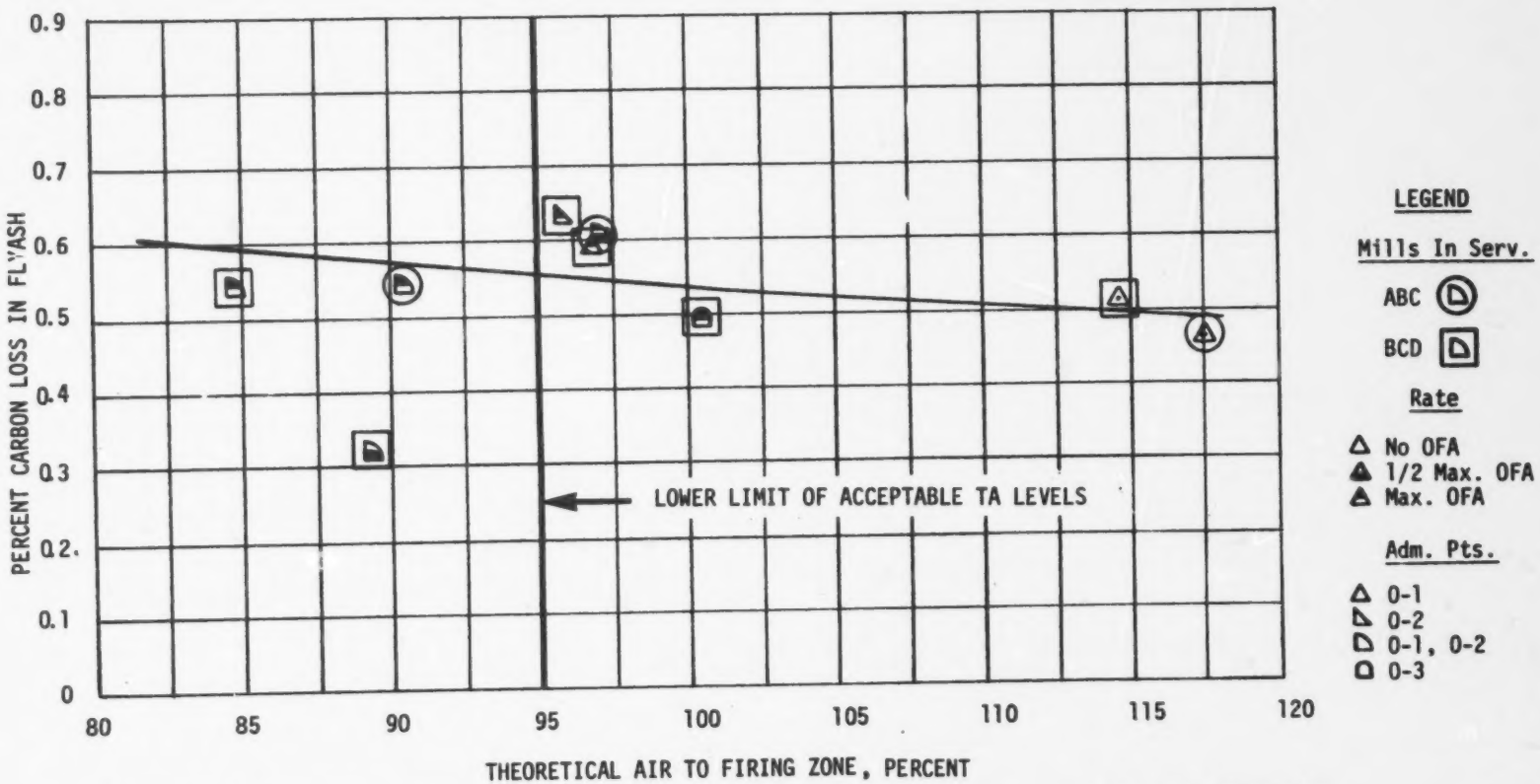


Figure 90: Percent carbon loss vs. theoretical air to firing zone, overfire air location rate & velocity variation, Tests 15-23

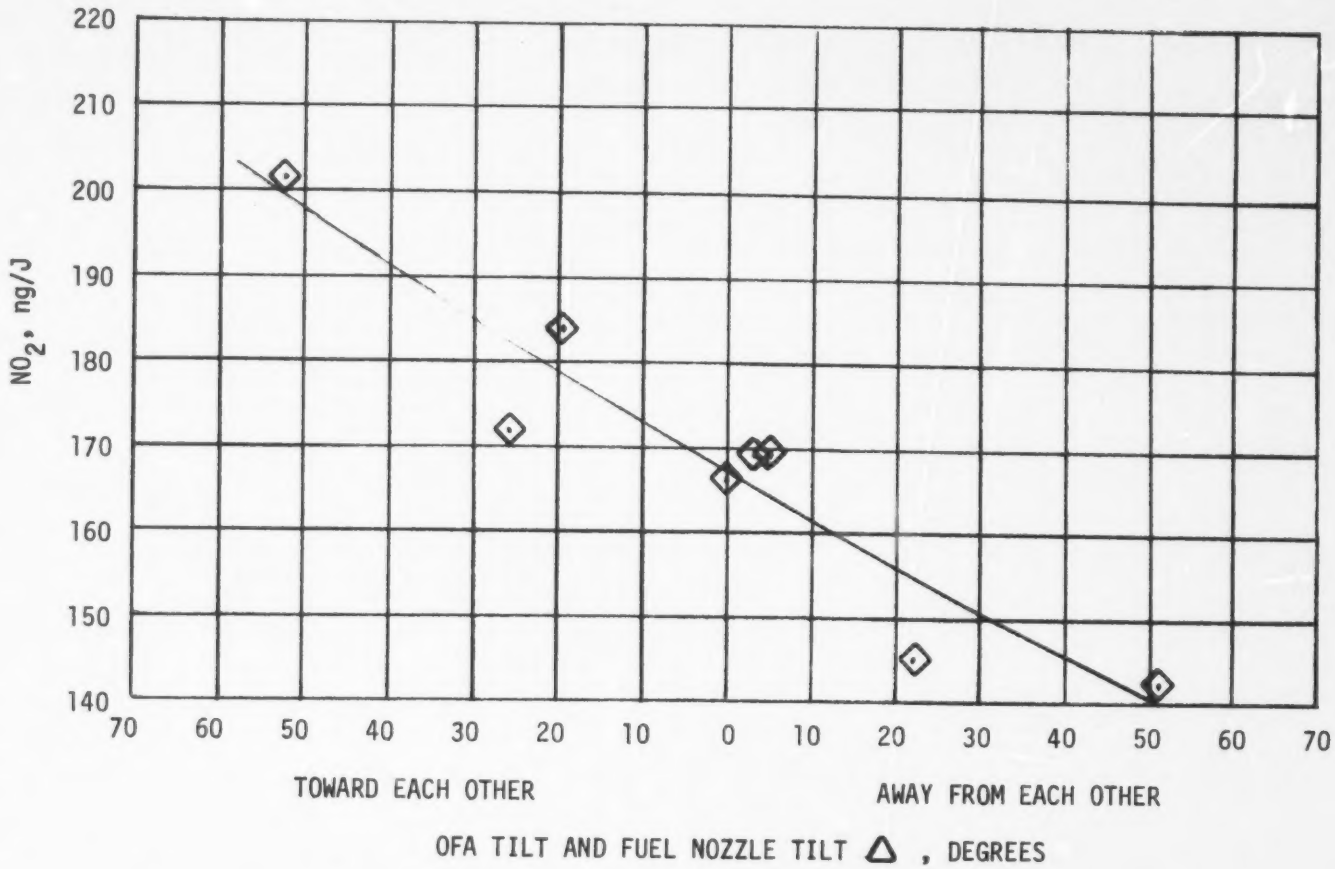


Figure 91: NO_2 vs. OFA tilt and fuel nozzle tilt differential, OFA tilt variation Tests 24-33

When the OFA tilts are maximum minus and the fuel nozzle tilts maximum plus, the term overfire air becomes ambiguous. The actual overfire air is less than the reported value, because the air is being forced down into the raised firing zone. At this point where the combined fuel nozzle and OFA tilt differential is 52 degrees toward each other, the NO_x emission level reaches a maximum of 202.1 ng/J.

Percent carbon loss in the fly ash exhibits a definite increase as the fuel nozzle tilts and OFA tilts move away from each other. This can be seen in Figure 92.

CO emission levels also show an increase as the tilt differential increases, yet there is enough total excess air to maintain an acceptable emission level as shown in Figure 93.

Flame stability arises as a limiting factor in variation of the tilts. As the tilts move substantially away from each other, the fire becomes unstable and pulsing may result. Test 29 was performed with a fuel nozzle and OFA tilt differential of 51 degrees away from each other. NO_x emission levels decreased to 142.3 ng/J, yet the CO emission levels began to increase and the fire appeared less stable. Maintaining the fuel nozzle tilts and OFA tilts at approximately equal tilt angles resulted in acceptable flame stability as well as reduced NO_x emission levels.

For all OFA tilt variation tests the NO_x emissions level obtained was below the EPA limit of 301 ng/J.

Load Variation at Optimum Conditions

Tests 30 through 35 were conducted to evaluate unit performance and emission levels at optimum operating conditions as determined during Tests 15 through 29. Tests were conducted over the unit load range at varying furnace waterwall slagging conditions. The NO_x emission level results of this series of tests versus unit loading, expressed as main steam flow, are shown on Figure 94.

Test No.	Main Steam Flow kg/s	NO_2 ng/J	CO ng/J	X-S Air %	Theo. Air To Firing Zone - %	Unit Effic. %	WW Slag
30	116	169.6	7.9	21.6	90.7	89.0	Clean
31	87	169.1	7.9	25.2	89.4	89.1	Clean
32	57	197.8	7.4	46.9	88.5	89.2	Clean
33	114	166.5	7.5	27.4	94.6	89.0	Max
34	86	145.2	8.0	27.4	90.6	88.2	Max
35	57	156.4	7.6	45.9	88.5	89.0	Max

This figure illustrates the range of NO_2 levels obtained both during baseline (after modification) and optimum unit operations. Not all the baseline tests are included as in some cases unit operation was felt to depart excessively from normal operations. Low excess air operation can be cited as an example.

The wide range of NO_2 levels obtained, particularly during the baseline tests

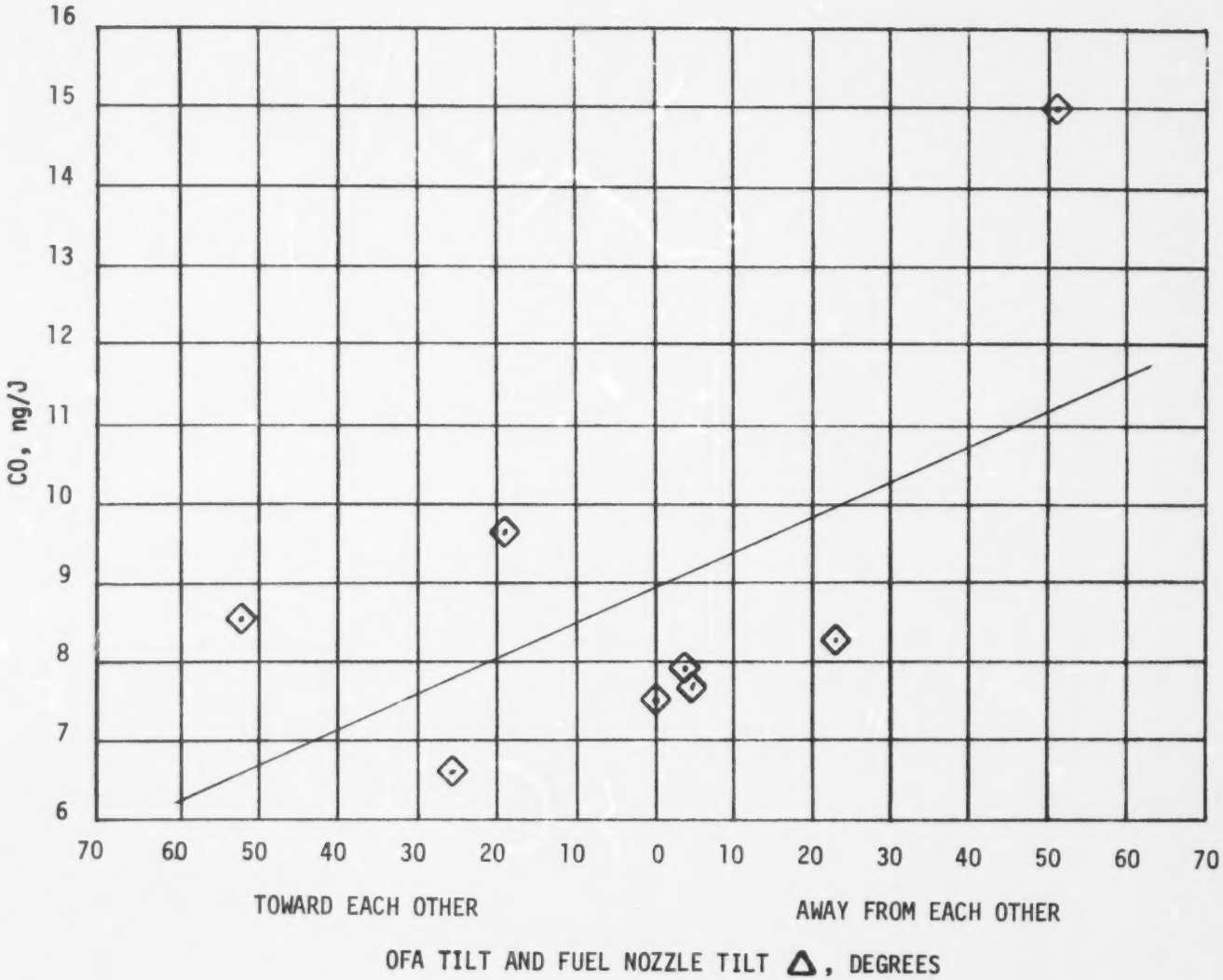


Figure 92: CO vs. OFA tilt and fuel nozzle tilt differential, OFA variation Tests 24-33

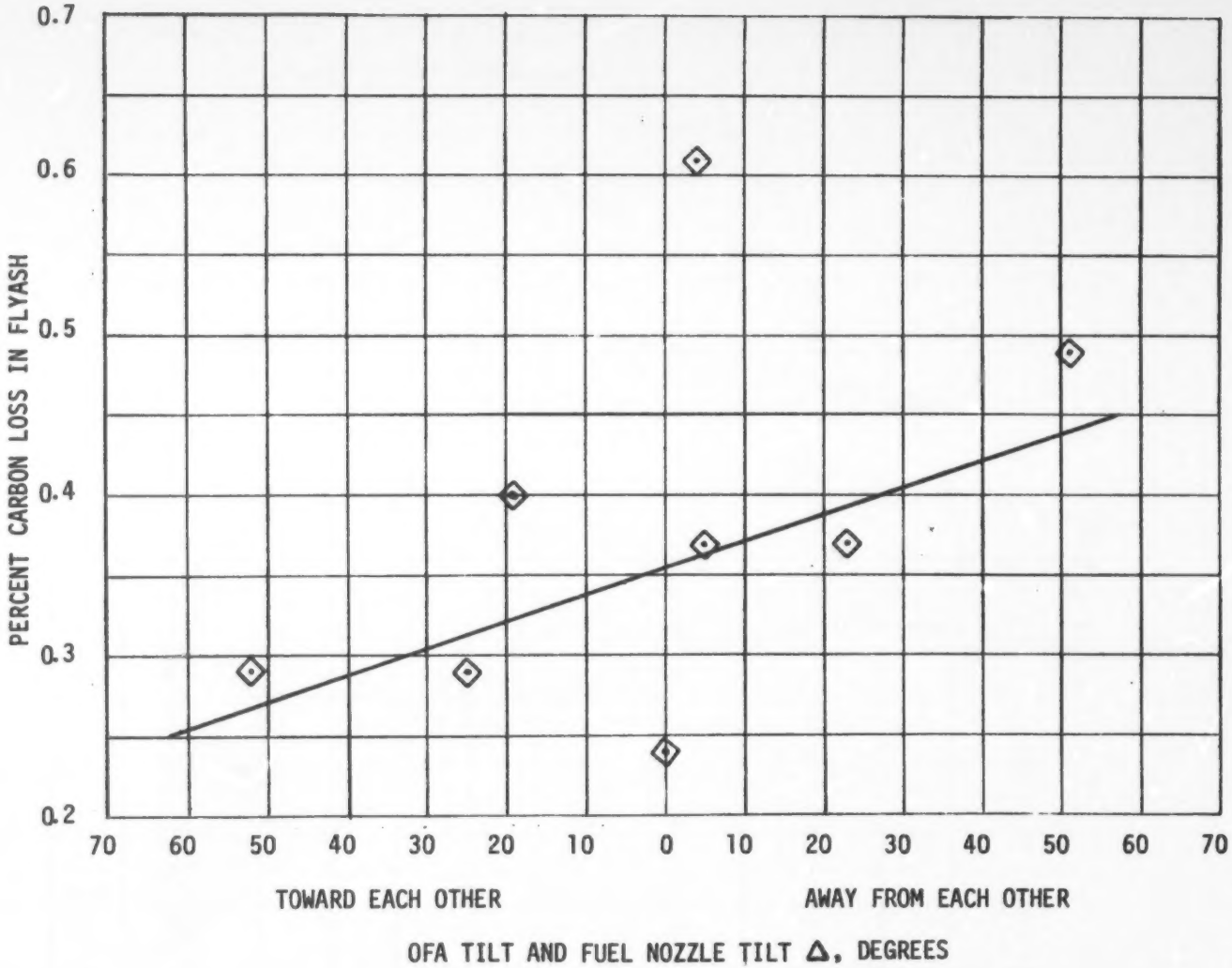


Figure 93: Percent carbon loss vs. OFA tilt and fuel nozzle tilt differential, OFA tilt variation, Tests 24-33

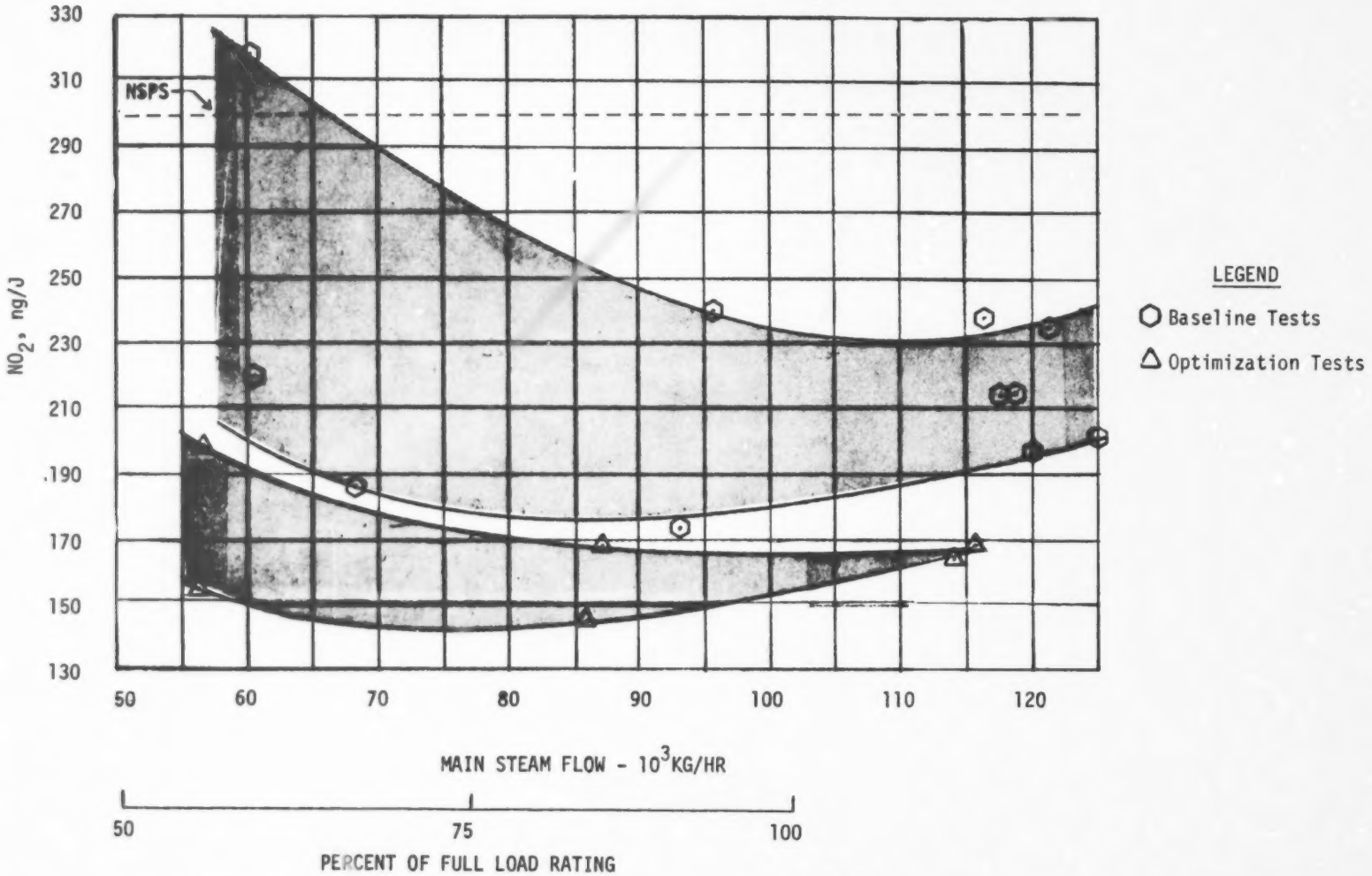


Figure 94: NO_2 vs. main steam flow, ranges for normal & optimum operation

are due to variations in unit operating parameters such as excess air level. During the optimization tests, total excess air at the unit economizer outlet was maintained between 20 and 28% at full and 3/4 load and 45 to 47% at 1/2 load and fuel nozzle tilts raised or lowered as required to maintain acceptable reheat and superheat outlet temperatures. Also minimum excess air levels were established on the basis of maintaining acceptable CO emission levels and flame stability.

Tests 30, 31 and 32 were conducted as a series and no problems were encountered while changing load with optimum operation.

FURNACE PERFORMANCE

During the test program, furnace performance was monitored by use of chrodal thermocouples installed in the furnace waterwalls. A schematic of the thermocouple locations is shown in Figure 95 and a tabulation of the absorption rates obtained is presented on Sheets C6, C7 and C8. The temperatures and corresponding absorption rates were found to vary significantly with wall slag conditions making data interpretation difficult. The method finally arrived at as representing an accurate indication of furnace performance is as follows:

The front and right side wall centertube profiles were plotted as shown in Figure 96 and the average of these profiles determined. It should be noted that the maximum and minimum profiles shown do not represent individual walls in every case, i.e., at given furnace elevations the maximum rate shown may switch from wall to wall.

For comparison of optimum and normal unit operation with respect to furnace performance, three full load tests with similar furnace slagging conditions, etc., were selected for comparison. The average centerline profiles for these tests (14, 24, 33) were determined, as shown on Figures 96, 97 and 98, and then plotted together as shown on Figure 99. As shown, furnace performance remained essentially unchanged when furnace slagging effects are taken into account.

It should be noted here that obtaining desired slag conditions proved to be difficult and somewhat unpredictable during overfire air operation. This situation was most pronounced in the firing zone where slag accumulations would normally shed themselves before appreciable accumulations could be built up.

WATERWALL CORROSION COUPON EVALUATION

Following completion of the steady state phases of the baseline, biased firing and overfire air test programs, thirty (30) day waterwall corrosion coupon evaluations were performed. The purpose of these evaluations was to determine whether any measurable changes in coupon weight losses could be obtained for the various firing modes studied.

The individual probes were exposed at five locations on the furnace front wall as shown on Figure 69. The coupon temperatures were maintained at the same levels for each 30 day run and a typical trace of the control temperature range for each of the twenty coupons is shown on Figure 70.

The individual coupon weights were determined before and after each thirty day test and the individual coupon and average probe weight losses are shown on

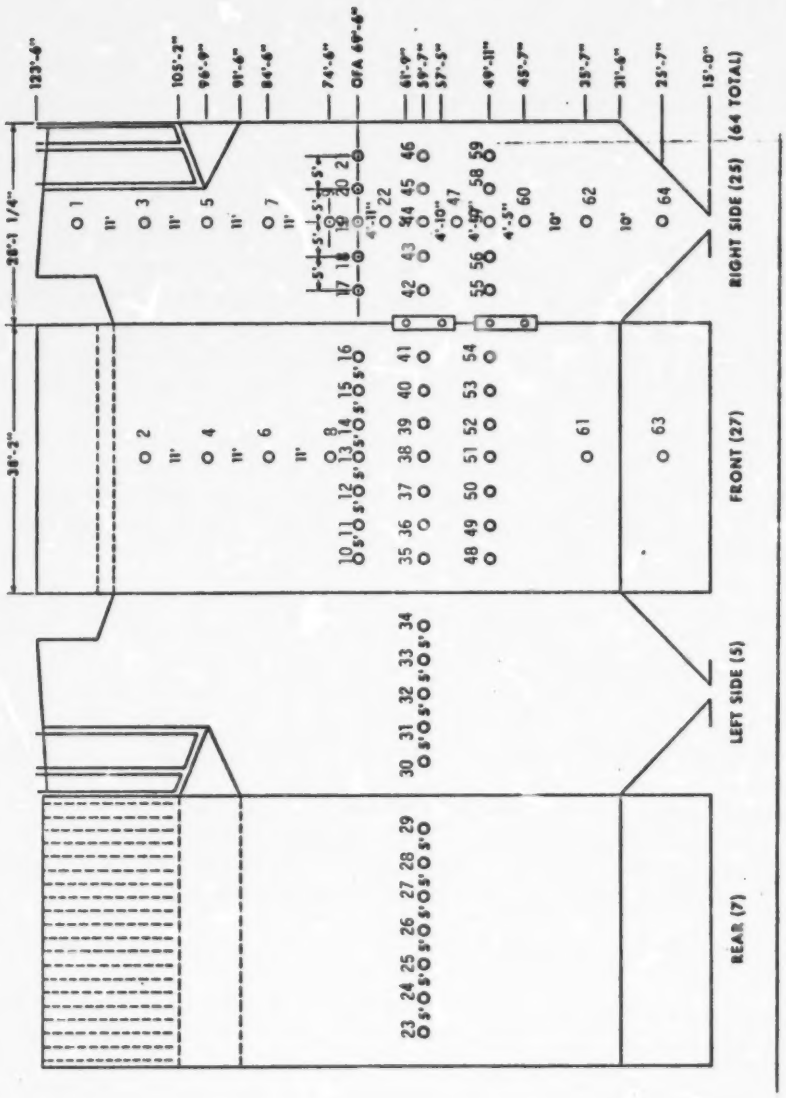


Figure 95: Chordal thermocouple locations on the furnace waterwalls

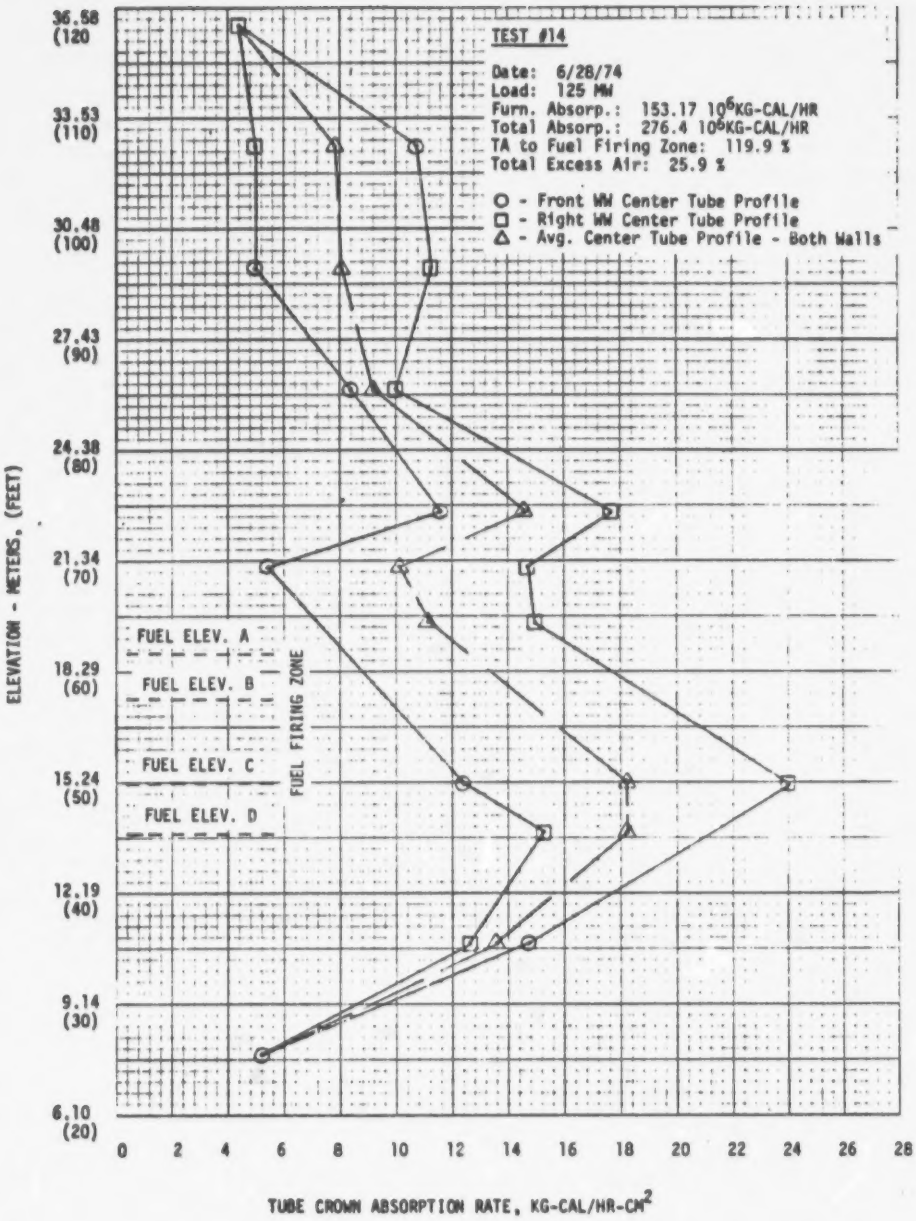


Figure 96: Average centerline absorption profile, Test 14

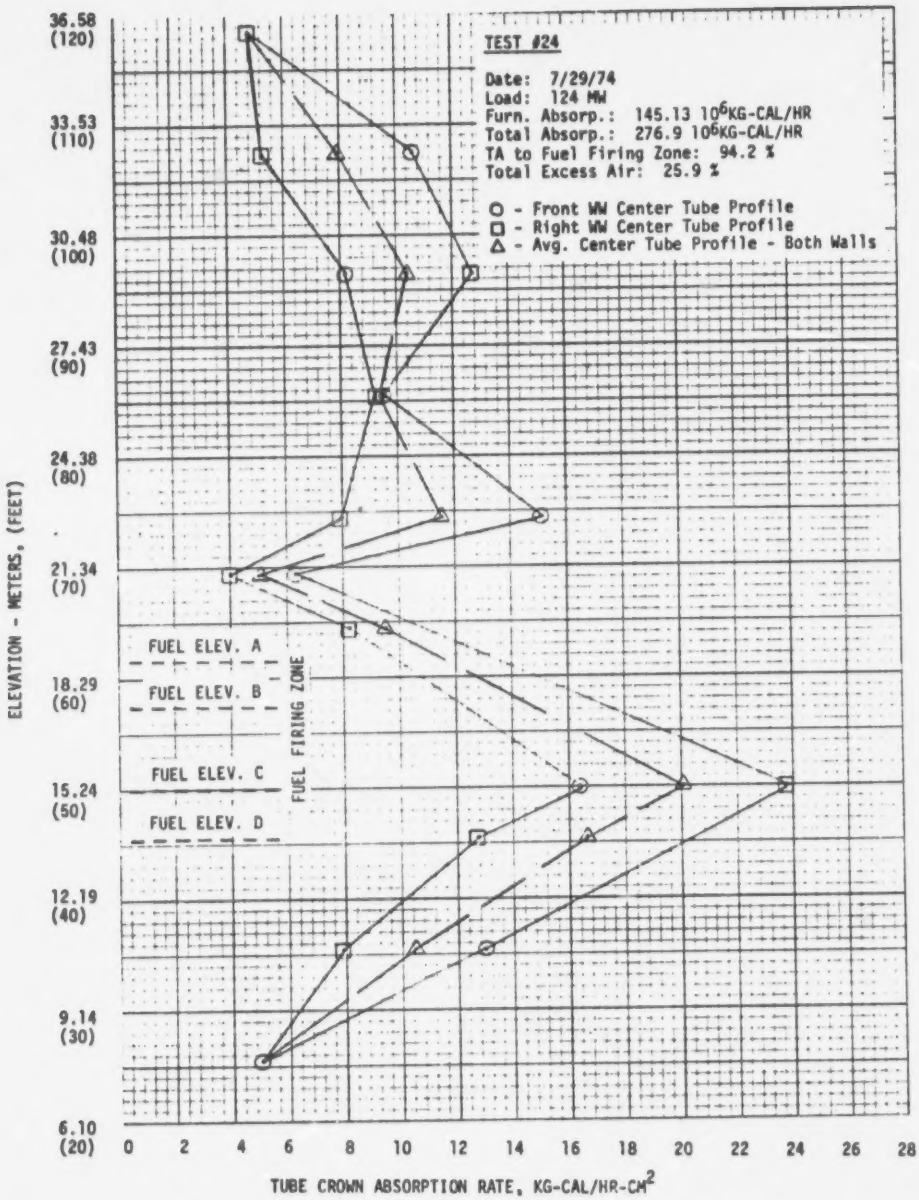


Figure 97: Average centerline absorption profile, Test 24

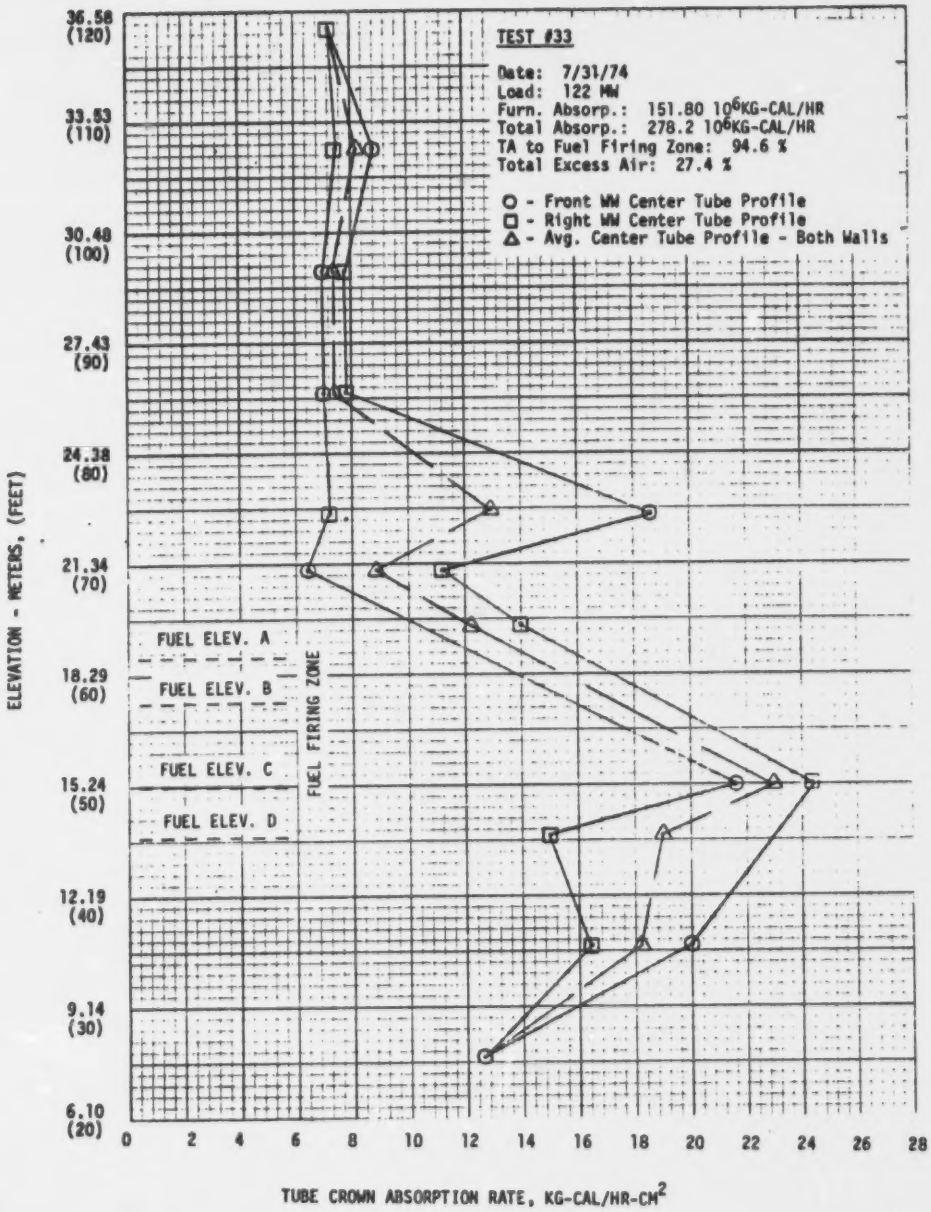


Figure 98: Average centerline absorption profile, Test 33

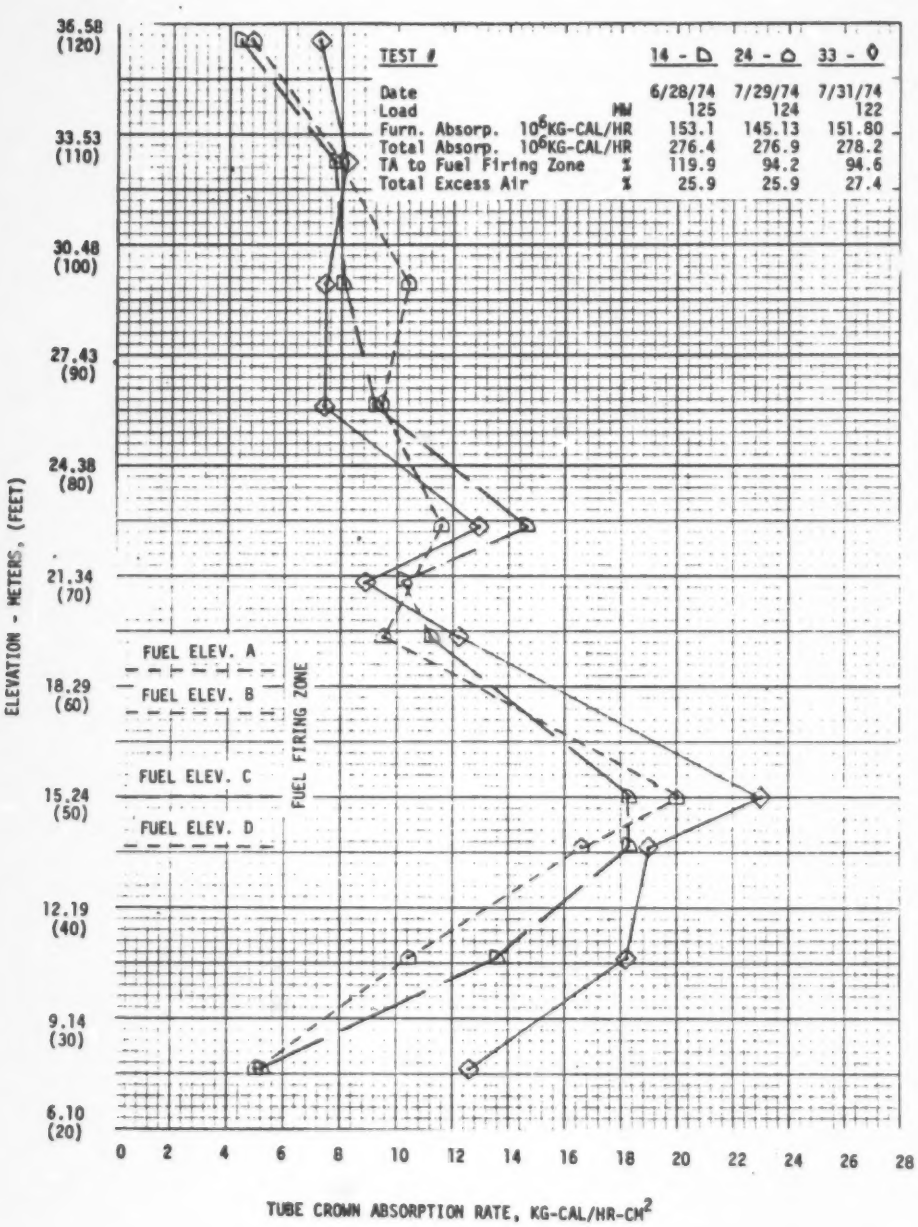


Figure 99: Average centerline absorption profile, All Tests

Sheets C9, C10 and C11. The weight losses are calculated as mg/cm^2 of coupon surface area. Of the sixty coupons exposed, three were damaged during disassembly and were therefore not included in the weight loss determinations. The affected coupons were as follows: Coupon K-1, baseline study, and coupons 2-1 and 2-4, overfire air study. In addition, five coupons from probes T and N of the overfire air study resisted disassembly and were therefore weighed as single units and average weight losses were determined.

Figures 100, 101 and 102 show the unit load schedules for each of the 30 day test periods.

The biased firing study was conducted with the top fuel firing elevation out of service as this operating condition was shown during steady state biased firing tests to produce the lowest NO_x emission level of the biasing modes studied. The overfire air study was conducted using an "optimized" operating mode as determined during the overfire air steady state tests.

Throughout each study the following damper positions were maintained over the load ranges indicated.

At unit loadings below 56.7 kg/s steam flow, with two elevations of mills in service, damper positions were maintained as follows:

Biased Firing Operation			Overfire Air Operation	
			OFA Dampers	100 100
Coal	Auxiliary		Coal	Auxiliary
0	0		100	100
0	0		30	50
30	100 100	Combustion Air Only	0	50 0
30	50		0	0
				0

From 56.7 to 75.5 kg/s steam flow, with three elevations of mills in service, the damper positions were as follows:

Biased Firing Operation			Overfire Air Operation	
			OFA Dampers	100 100
Coal	Auxiliary		Coal	Auxiliary
100	100 50	Combustion Air Only	100	100 50

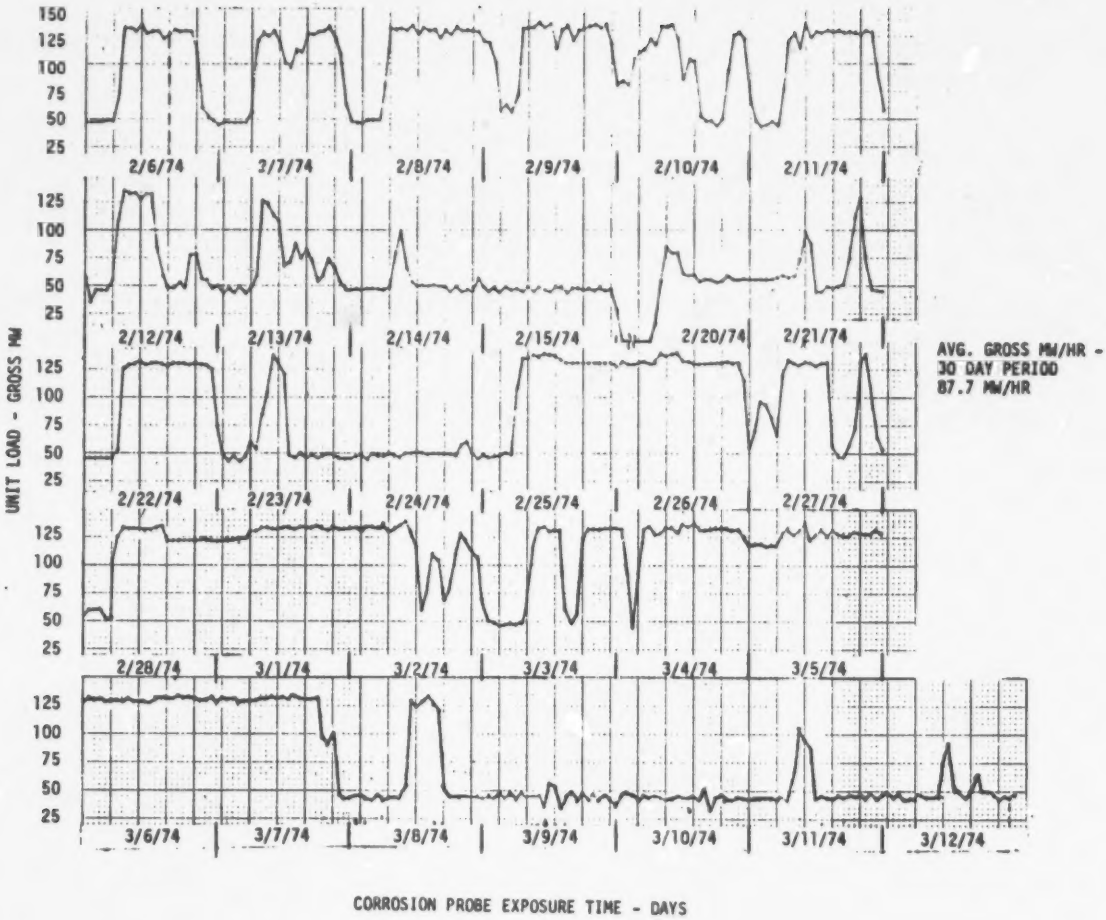


Figure 100: Gross MW loading vs. time - baseline corrosion probe study

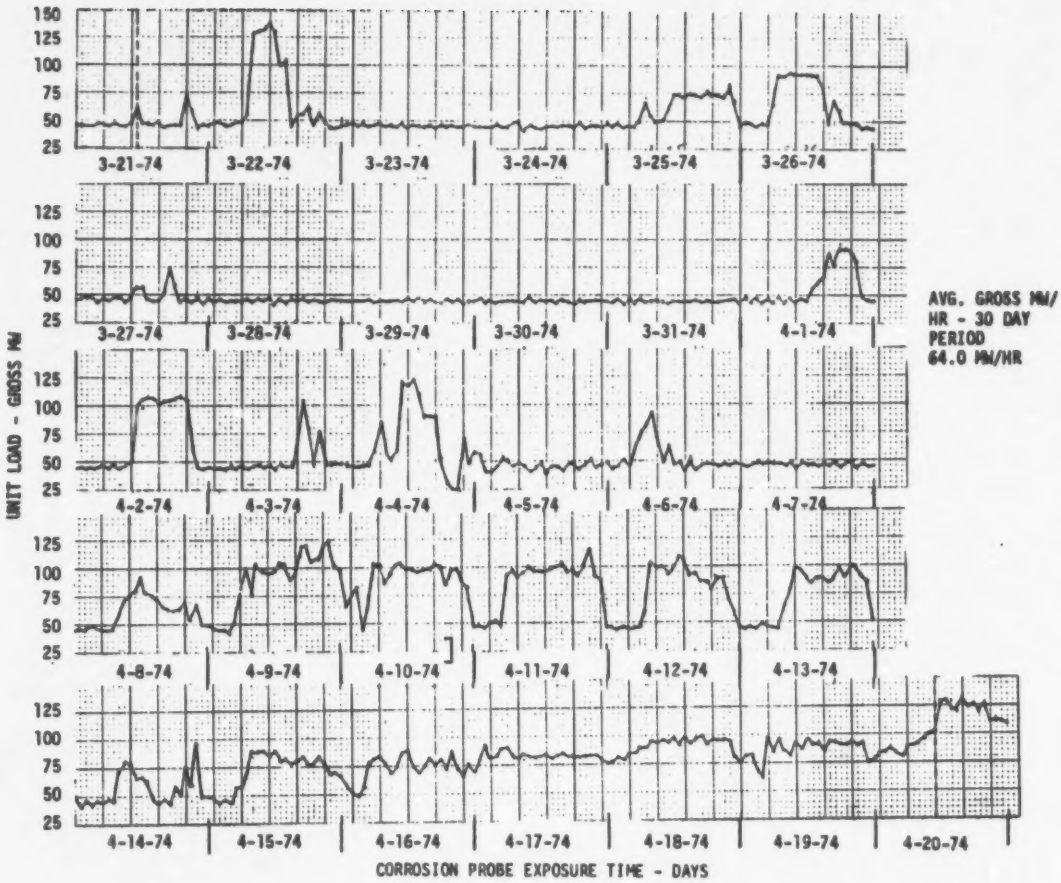


Figure 101: Gross MW loading vs. time - biased firing corrosion probe study

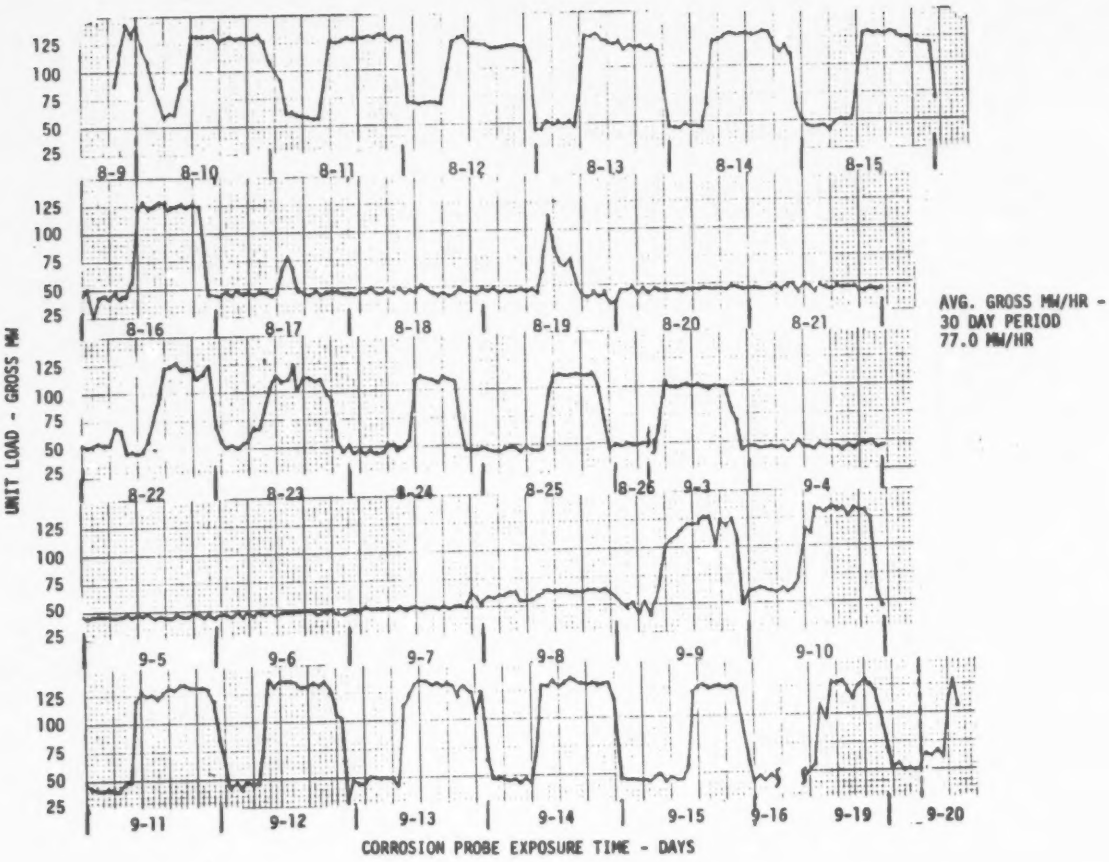


Figure 102: Gross MW loading vs. time - overfire air corrosion probe study

Biased Firing Operation (Cont.)		Overfire Air Operation (Cont.)	
Coal	Auxiliary	Coal	Auxiliary
20		30	
	50		50
	50		50
20		30	
	50		50
20		0	
	50		0

At unit loadings above 75.5 kg/s to the maximum steam flow with the maximum elevations of mills in service, the following damper positions were maintained.*

Biased Firing Operation		Overfire Air Operation	
		OFA Dampers	100
			100
Coal	Auxiliary	Coal	Auxiliary
	100 - Combustion Air Only		100
100		100	
	50		50
30		30	
	50		50
	50		50
30		30	
	50		50
30		30	
	50		50

The percent oxygen was monitored daily during each thirty day study at each probe location and was found to be essentially the same for the various test conditions ranging between 16 and 19 percent O_2.

The weight losses calculated for the biased and overfire air portion of the test program were found to be greater than those for the baseline tests. The average weight losses for all five probes were as follows:

Baseline	Biased Firing	Overfire Air
2.6381 mg/cm^2	4.6429 mg/cm^2	4.4419 mg/cm^2

These values are within the range of losses which would be expected for oxidation of carbon steel for a 30 day period. To verify this premise control

* At no time during the biased firing study was the top elevation coal pulverizer placed in service. Maximum unit loading was therefore limited to the maximum with the lower three mills in service.

studies were conducted in C-E's Kreisinger Development Laboratory using probes exposed during the biased firing study. These probes were cleaned and prepared in an identical manner to those used for furnace exposure and placed in a muffle furnace for 30 and 60 day exposures at 399°C with a fresh air exchange. The test results were as follows:

Probe	Wt. Loss mg/cm^2 - 30 Days
M (30 day)	4.7999
Q (30 day)	4.7741
R (60 day)	5.1571/2 = 2.5785
B (60 day)	8.3493/2 = 4.1746

These results indicate that the test coupons oxidized more rapidly during the first 30 days exposure with average weight losses decreasing in the second thirty days. Based on these results, it appears that the differences in weight losses observed during the test program are within the ranges to be expected from oxidation alone.

Chemical analysis of deposits taken during the test program does not, in itself, show that molten phase attack has occurred. The composition of the deposits does show some differences, primarily in the iron content as noted on Figure 103. The deposit collected during the biased firing and overfire air tests show 50 and 35 percent iron, respectively, versus 30 percent in the baseline test. Higher iron is normally indicative of lower melting temperatures. However a certain quantity of CaO is necessary to flux the iron if it is to result in a low melting mixture. The CaO content is considerably less in the biased firing and overfire air tests as compared to that of the baseline test. Accordingly the fusibility temperatures are higher for the biased firing test and slightly higher for the overfire air tests. This agrees with observations made during the tests, i.e., deposits during biased firing were more friable and easily removed than in the baseline tests with the overfire air tests falling closer to baseline operation.

For comparison fusibilities and compositions have been given in Figure 39 for the coal ash as fired. This points out the selective deposition of certain constituents in the coal ash, like iron, and also shows that resultant fusibility temperatures of deposits can be significantly different than the coal ash as fired.

	Waterwall Slag Sample Baseline Test	Coal Ash (As-Fired)	Waterwall Slag Sample Biased Firing Test	Waterwall Slag Sample Overfire Air Test
Ash Fusibility				
IT	1930	2150	2060	1930
ST	2090	2410	2170	2090
HT	2200	2500	+2700	2250
FT	2500	2620	+2700	----
Ash Composition				
SiO_2	46.2	45.8	38.4	38.5
Al_2O_3	18.4	30.7	10.3	18.1
Fe_2O_3	29.9	13.9	50.0	35.4
CaO	3.9	1.8	1.0	1.8
MgO	0.8	1.3	0.3	0.9
Na_2O	0.32	0.4	0.1	0.4
K_2O	0.61	1.4	0.7	1.9
TiO_2	N.R.	0.8	N.R.	1.0
P_2O_5	N.R.	0.5	N.R.	N.R.
SO_3	0.34	1.2	0.8	0.4
	100.4	97.8	101.5	98.4

Figure 103: Ash Analysis

SECTION IV - APPLICATION GUIDELINES

INTRODUCTION

This section presents the results of Task IX of the Phase II - "Program for Reduction of NO_x from Tangential Coal Fired Boilers" performed under the sponsorship of the Office of Research and Development of the Environmental Protection Agency (Contract 68-02-1367). These results were subsequently updated under Task VII d of Contract 68-02-1486, "Staged Combustion Technology for Tangentially Fired Utility Boilers Burning Western U.S. Coal Types." The results presented are based on field performance tests performed at Alabama Power Company, Barry #2; Utah Power & Light Company, Huntington Canyon #2; Wisconsin Power & Light Company, Columbia #1 and current contractor experience.

The utilization of overfire air as an NO_x control technique is discussed relative to the following areas of interest:

1. Necessary equipment modifications and costs (as of January, 1977) associated with applying this technology to existing steam generators.

2. Specific limitations to the general applications of the technology developed.

3. Emission control and cost effectiveness of applying the developed technology to new steam generator designs.

CONCLUSIONS

1. Prior to incorporating overfire air as an NO_x control system on existing unit designs, an exploratory test program must be performed to determine the acceptability of the unit for modification.

2. The costs of installing an overfire air system on an existing unit could range between 2 to 4 times the cost as included on a new unit design. Based on January, 1977 estimates, existing unit modification costs could range from 0.24 to 1.8 $/kw, depending on unit size.

3. Approximately 40% of the existing coal fired units in the United States are of tangential design and could conceivably be modified to incorporate overfire air systems.

4. Unit size, heat rate and expected life must be considered in deciding whether modifications are justified.

5. Incorporation of an overfire air system will not significantly affect unit performance.

6. A large percentage of the existing tangentially coal fired units in the United States can meet current EPA standards for NO_x emission levels. The necessity of applying the overfire air technique for NO_x control should therefore be established prior to committing a unit for modification.

RECOMMENDATIONS

EXISTING STEAM GENERATING UNITS

The applicability of the technology developed in the course of this project should be qualified by the following conditions:

1. Any unit under consideration should be subjected to an exploratory test program to determine the necessity of modification with respect to applicable NO_x compliance limits. The minimum test requirements recommended for such a study would consist of studying the effect of available process variables such as excess air level. The minimum test data would consist of NO_x, CO for combustion efficiency and sufficient board or test data to identify changes in unit operating characteristics.

2. A review should be made of the unit and turbine useful life expectancy, unit size versus modification costs, and unit heat rate.

NEW STEAM GENERATING UNITS

All tangentially coal fired units since approximately 1970 have included Overfire Air (OFA) systems in the original unit design. The OFA system is therefore not considered by Combustion Engineering, Inc. as an additional NO_x control device.

DISCUSSION

The effectiveness of overfire air operation in reducing NO_x emissions from existing utility steam generators was evaluated by selecting, modifying, testing one unit and selecting and testing two additional units designed with OFA systems. The effects of OFA system operation on unit performance and emission control was studied in each of these units. The modified test unit, Alabama Power Company's Barry #2, is a natural circulation, balanced draft design, firing coal through four elevations of tilting tangential fuel nozzles. Unit capacity at maximum continuous rating (MCR) is 113 kg/s main steam flow with a superheat outlet temperature and pressure of 538°C and 12.9 MPa.

The units designed with overfire air systems and burning Western coal types are described as follows:

Utah Power & Light Company, Huntington Canyon #2 is a controlled circulation, balanced draft design firing a Western bituminous coal type through five elevations of tilting tangential fuel nozzles. Unit capacity at maximum continuous rating (MCR) is 382 kg/s main steam flow with a superheat outlet temperature and pressure of 541°C and 18.2 MPa.

Wisconsin Power & Light Company, Columbia #1 is a controlled circulation, balanced draft design firing a Western subbituminous coal type through six elevations of tilting tangential fuel nozzles. Unit capacity at maximum continuous rating (MCR) is 478 kg/s main steam flow with a superheat outlet temperature and pressure of 541°C and 18.1 MPa.

Superheat and reheat temperatures for the three units are controlled by fuel nozzle tilt and spray desuperheating.

In order to evaluate unit performance during these studies, necessary steam, water, air and gas temperature and pressure measurements were performed as well as NO_x, CO, O_2, THC, SO_2 and carbon loss determinations to assess emission performance. The test program for the modified unit was conducted in three phases consisting of baseline and biased firing portions conducted prior to modification and baseline and overfire air portions conducted after unit modification. The effect of the modification on unit performance was found to be insignificant and the test data summaries for each phase are shown in Appendices A, B and C. Similar three phase programs were conducted on the two test units burning Western coal types evaluating baseline, biased firing and overfire air operation. Short term comparative corrosion tests were conducted on each unit over thirty day periods using corrosion coupons, which are made of the same material as the waterwalls. During this evaluation, both normal and OFA operation was evaluated. The unit load schedules for the baseline and biased firing and overfire air evaluations are shown on Figures 39, 40, 62, 63, 100, 101 and 102. The respective data summaries are shown on Sheets A1 through A6; B1 through B6 and C1 through C5. Corrosion coupon locations are shown on Figures 37, 60 and 69.

DESIGN AND DESCRIPTION OF OFA SYSTEMS

The overfire air system as incorporated in tangential coal fired furnaces consists of air compartments and registers, ductwork, flow control dampers and nozzle tilting mechanisms. A typical arrangement of this system is shown on Figure 15. The overfire air compartments and registers are designed as vertical extensions of the corner windboxes unless, as in the case of some existing units, modification at that location is not possible due to structural considerations.

In the latter case, as was the situation with the modified test unit, the separate compartments and registers were installed within three meters of the top of the existing windbox. As shown on Figure 67, this arrangement requires additional ductwork for supplying air to the OFA system.

Control dampers for regulating the OFA flow rate should be coordinated with the windbox fuel and auxiliary air compartment dampers to correctly proportion air flow as required for various operating modes.

An independent OFA register tilt mechanism should also be provided on retrofits of existing units to permit coordinating these registers with the fuel and air nozzle tilts.

The overfire air registers and ducts should be sized for 15% of the full load secondary* air flow using the same register and duct velocities as the windbox. Each overfire air port consists of two registers above each windbox, usually as an extension of the windbox.

FIELD TEST PROGRAM

The field performance tests conducted at Barry No. 2 firing Eastern bituminous coal and at Huntington Canyon No. 2 and Columbia No. 1 firing Western bituminous coals respectively showed that an overfire air system on a tangential coal fired furnace can reduce NO_x emissions with no detriment to unit operation or maintenance. NO_x emission reductions of 20 to 30% were obtained with 15 to 20 percent overfire air when operating at a total unit excess air of approximately 15 to 25 percent as measured at the economizer outlet. This condition provided an average fuel firing zone stoichiometry of 95 to 105 percent of theoretical air. The firing zone stoichiometries attainable at given overall excess air levels did vary somewhat from unit to unit. Stoichiometries below the 95 percent level did not result in large enough decreases in NO_x levels to justify their use. Biased firing (removing the top burner elevation from service), while potentially as effective, necessitated a reduction in unit loading and is therefore less desirable a method of NO_x control. In essence, this method uses the uppermost fuel and air compartment as a windbox extension.

When using overfire air as a means of decreasing the theoretical air to the fuel firing zone the percent carbon in the fly ash and CO emission levels were less

* Secondary air does not include coal pulverizer transport air.

affected than when operating with low excess air.* This is due to the ability to maintain acceptable total excess air levels, as measured at the economizer outlet, during overfire air operation while the theoretical air to the fuel firing zone is reduced.

Furnace performance as indicated by waterwall slag accumulations, visual observations and absorption rates, was not significantly affected by overfire air operation.

On existing units where, for structural reasons, an overfire air port might not be installed as a windbox extension, test results indicate that the centerline of the overfire air port be kept within three meters of the centerline of the top fuel elevation. Distances greater than three meters did not result in decreased NO_x levels. Changes within the three meters limit did affect NO_x levels slightly with the NO_x levels increasing as the distance decreased.

The overfire air nozzles should tilt in unison with the fuel nozzles where possible. Tilting the overfire air and fuel nozzles towards each other directs the overfire air into the fuel admission zone thereby negating the original intent, while tilting the nozzles away from each other may result in decreased flame stability. If the overfire air nozzle tilt is fixed in a horizontal position NO_x levels would probably then vary to a limited extent with fuel nozzle position. In other words, the NO_x levels may increase or decrease as the total included angle between the fuel and OFA nozzles is decreased or increased respectively.

The results of the 30 day baseline, biased firing and overfire air corrosion coupon runs indicate that the overfire air operation for low NO_x optimization did not result in significant increases in corrosion coupon degradation. The results of this study are shown on Sheets A57 and A58, B45 and B46 and C9 through C11. Potential long term corrosion effects were not evaluated as part of this program.

EXPLORATORY FIELD TEST PROGRAM - EXISTING UNITS

To determine both the necessity and acceptability of applying the OFA technique for NO_x emissions control on existing tangentially fired units, an evaluation should be performed prior to committing the unit to modification.

This evaluation should include the study of existing process variables, such as excess air, as an NO_x control method. If these techniques should prove unsatisfactory, the program should then be expanded to evaluate the effect of biased firing on NO_x emissions. This technique consists of removing the top fuel elevations from service and using the upper air and fuel compartments for the introduction of overfire air. This evaluation should be conducted at the maximum possible unit loading with one pulverizer out of service and otherwise normal operation.

During biased firing operation, changes in total excess air required to maintain acceptable CO levels, the amount of carryover from the furnace outlet, and

* A minimum of 20 to 25 percent excess air was generally established for the test units.

furnace slagging tendencies should be observed. Carryover could be visually observed, while increased slagging might be evaluated both visually and in terms of bottom ash handling system performance. Outlet steam temperatures and air heater exit gas temperatures should also be observed for comparison of normal operation.

The minimum instrumentation necessary for a comprehensive evaluation is as follows:

Unit Performance

Superheat (S.H.) Outlet Temp.	Calibrated Board Data*
Reheat (R.H.) Outlet Temp.	Calibrated Board Data*
R.H. & S.H. Spray Flows	Calibrated Board Data*
Gas Temp. Lvg. Air Heater (A.H.)	Thermocouple Grid in A.H. Outlet Duct
Excess Air Lvg. A.H.	Gas Sampling Grid in A.H. Outlet Duct
Furnace Carryover	Visual Observation
Furnace Slagging	Visual Observation & Ash System Performance, Nozzle Tilt Changes & Desuperheating Sprays
Unit Gas Side Pressure Drop	Calibrated Board Readings*

Emissions Performance

NO_x, CO & O_2	Gas Sampling Grid in A.H. Inlet Duct

EFFECT ON UNIT PERFORMANCE

The application of OFA as an NO_x control device spreads out the furnace fire, which reduces flame intensity and temperature and the initial oxygen concentration. These effects combine to limit the formation of oxides of nitrogen compounds with the reduced oxygen apparently affecting the formation of NO by the fuel bound nitrogen.

In the case of coal firing, the NO_x emissions originate from two sources, fuel bound and atmospheric nitrogen, and thus (NO) Total = $(NO)_{Fuel\ N} + (NO)_{N_2\ in\ air}$.

Test results from all three units indicated that as long as the total excess oxygen (fuel compartment O_2 + OFA O_2), as measured at the economizer, remains changed from the baseline condition, unit performance would remain unaffected. In some cases, however, a slightly increased total oxygen may be required to prevent an increase in CO and unburned carbon emission levels. This situation

* If not available, test instrumentation should be considered.

could be simulated with a biased firing test (top fuel elevation out of service) conducted during the exploratory program to determine the necessity of unit modification. While this approach will necessitate a reduction in unit loading, testing should be conducted at the highest possible loading obtainable for comparison to normal unit operation.

Otherwise, overall steam generator performance, including fan power, final steam temperatures, furnace wall tube temperatures and corrosion, and unit efficiency remain essentially unchanged.

The effect on furnace slagging has been found to vary somewhat with coal types and in particular with blends of various coals. Therefore, since coal types vary widely, the effect of changing firing zone stoichiometries on slagging tendencies should be evaluated during the exploratory program, again by using the biased firing technique. Where evaluating units with spare coal pulverizer capacity, this check should, if at all possible, be made at, or close, to full unit rating, particularly from the standpoint of evaluating unit slagging tendencies. A minimum evaluation period of one week is recommended for studying slagging tendencies.

On some units, the spreading out of the furnace fire might result in some combustible carryover from the unit furnace to the superheat sections. The tendency toward this condition can also be evaluated during the exploratory program by visual observation and watching for changes in unit performance.

ECONOMIC EVALUATION

The cost of incorporating overfire air systems on existing and new unit designs was evaluated for steam generating units from 125 to 1000 MW capacity. The results of this study are shown on Figure 104.

The cost estimates for the revision of existing units are based on studies performed on units within this size range including the actual costs for modification of the Barry 2 unit. The cost estimates presented for including the overfire air system in new unit designs are based on current experience with these systems.

The accuracy of the January, 1977 cost estimates is plus or minus ten percent. Because the overfire air system is included as an integral part of new unit design, it is not therefore, considered as an optional or additional emissions control device. The costs of existing units could be from 0.24 to 1.8 $/kw, due to variations in existing unit design and construction which might make modifications more complicated. These costs may also vary and escalate with the prevailing economic climate.

The largest four-windbox (single cell) furnaces manufactured to date have been in the 625 MW size range at which point eight-windbox furnaces (generally divided into two cells) have been selected. Since an eight windbox tangentially fired furnace has double the firing corners of a four-windbox furnace, the costs of windboxes and ducts increase significantly.

The resulting increase in the cost of electricity generated is approximately

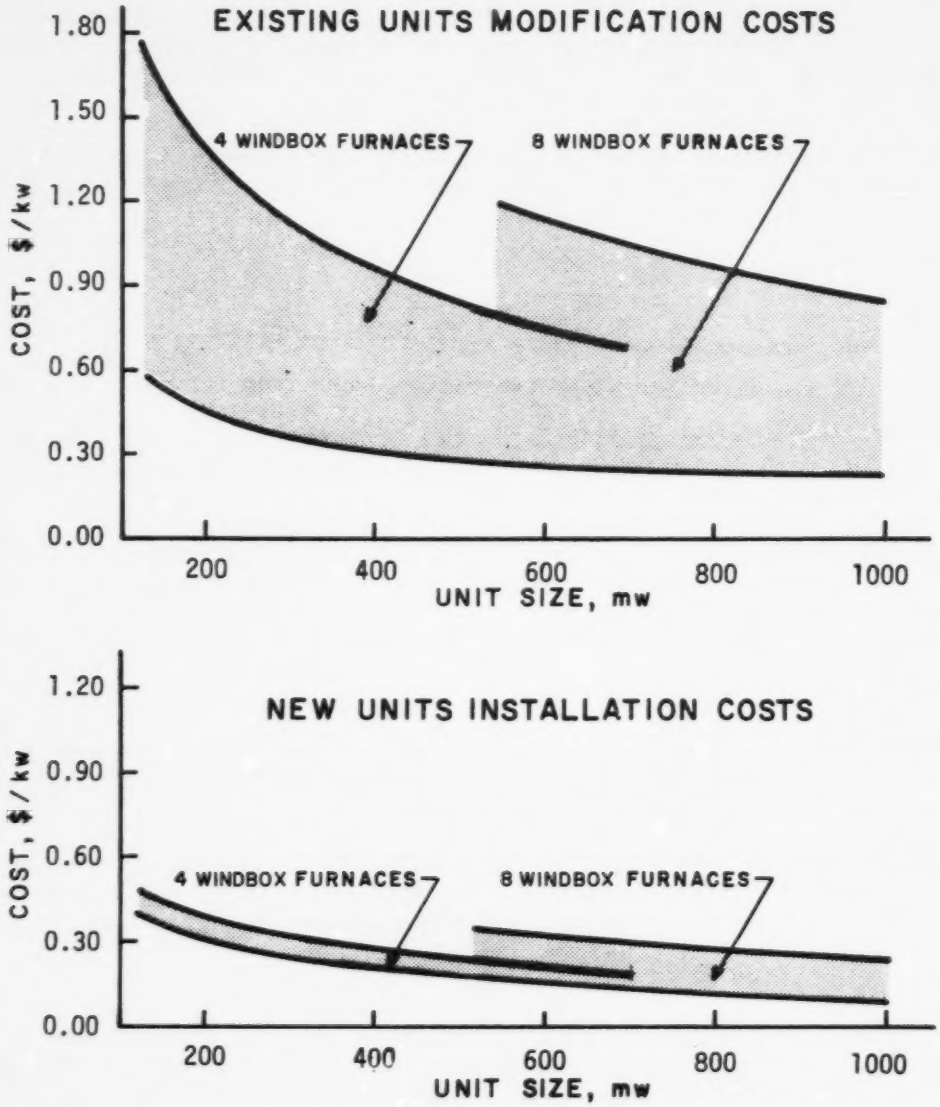


Figure 104: Overfire Air System Costs - Tangential coal fired steam generators - January, 1977 equipment costs

0.02% for a typical new 500 MW plant* costing 600 $/kw using coal costing 1.00 $/10^{6}BTU, as illustrated in Table 1. The overfire air system increases capital costs by 0.2 $/kw, and all other costs are unchanged. The mills/kwhr increase is 0.006.

An existing 500 MW plant has overfire air system costs up to 0.8 $/kw. Generation costs for a 600 $/kw plant increase by up to 0.10% or 0.026 mills/kwhr. An existing 500 MW plant which was installed for 300 $/kw and receives coal costing 0.50 $/10^{6}BTU has much lower operating costs than the previous example. The cost increase percentage is 0.14%, but the increase in mills/kwhr remains unchanged at 0.026, as shown in the last column of Table 1.

		$/KW
Coal Handling, Storage, Pulverizing, Ash Handling		53
SO_2 Scrubber System		90
Boiler, Air Heaters, Fans, Stack		74
Steam Turbine-Generator, Piping, Heaters, Water Treatment, Condenser, Cooling Towers		110
Structures, Sitework Foundations, Offices, Land, Workshops, Controls, Switchgear, Transformers		76
	Subtotal	403
Engineering, Construction		53
Contingency		44
Interest During Construction		100
	Total	600

The increases in generating costs (mills/kwhr) for typical 100 MW plants are approximately double the increases for 500 MW plants. The increases for 600 MW plants with divided furnaces are 25% to 35% higher; and the increases for 1000 MW plants are the same as for 500 MW plants.

Transmission and distribution costs are not included in these comparisons. These examples are only typical; a specific plant has to be evaluated on its particular economic criteria.

* January, 1977 equipment costs for 500 MW Coal Fired Power Plant with Limestone SO_2 Scrubbing System.

TABLE 1. COST OF ELECTRICITY GENERATED - 500 MW PLANTS
Net Heat Rate 9500 Btu/Kwhr
January, 1977 Equipment Costs

	New Plant Without Overfire Air	New Plant With Overfire Air	Recent Existing With Added Overfire Air	Older Existing Without Overfire Air	Older Existing With Added Overfire Air
Capital Costs, $/kw	600.00	600.20	600.80	300.00	300.80
Annual Cap. Cost, $	54,000,000 (a)	54,018,000	54,072,000	27,000,000 (b)	27,072,000
Annual Fuel Cost, $	26,000,000 (c)	26,000,000	26,000,000	13,000,000 (d)	13,000,000
Labor & Maint. (e), $	10,800,000	10,800,000	10,800,000	10,800,000	10,800,000
Total Annual Cost (f), $	90,800,000	90,818,000	90,872,000	50,800,000	50,872,000
Electricity Cost (g), Mills/kwhr	33.630	33.636	33.656	18.815	18.841
Increase, %	---	0.018	0.077	---	0.140
Increase, Mills/kwhr	---	0.006	0.026	---	0.026

Based on:
(a) Annual Fixed Charge Rate of 18% X 600 $/kw X 500,000 kw.
(b) 18% X 300 $/kw X 500,000 kw.
(c) 1.00 $/$10^6$ BTU coal cost X 5400 hr/yr X 500,000 kw X 9500 BTU/kwhr.
(d) 0.50 $/$10^6$ BTU coal cost X 5400 hr/yr X 500,000 kw X 9500 BTU/kwhr.
(e) Labor and maintenance cost of 4.0 mills/kwhr.
(f) 5400 hr/yr at 500 MW = 2700 gwhr/yr.
(g) Cost at plant bus bar; transmission and distribution not included.

APPLICABILITY

EXISTING STEAM GENERATING UNITS

In a specific existing plant, the exploratory field test program will provide the data to determine whether an overfire air system is needed to meet NO_x limits. If so, the biased firing tests will show operating effects such as combustible loss, corrosion, or furnace slagging. Favorable results from the field tests should be followed by an evaluation, as shown in Table 1, to determine whether modification costs are economically justified.

Economic considerations include plant age and efficiency. Will the plant continue to operate long enough to pay off the investment? The annual capital cost is inversely proportional to the number of years. Steam generator size also has an effect on the relative economics of overfire air system modifications. For example, the minimum modification cost is about $120,000, which is 4.8 $/kw for a 25 MW unit. With complications, 12 $/kw is possible for a 25 MW unit.

Approximately 40% of the existing coal fired units in the United States are of tangential design and could conceivably be modified to incorporate overfire air systems, if the field test and economic evaluation results are favorable. Since 1949, approximately 320 tangential units have been put into service without overfire air systems.

NEW STEAM GENERATING UNITS

At the current levels of NO_x limits, an overfire air system should be included as a standard design feature of a new unit. The technology is proven, and the cost is minimal when included in the original design.

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APPENDIX A

TEST DATA & RESULTS
FOR
WISCONSIN POWER & LIGHT COMPANY
COLUMBIA ENERGY CENTER
UNIT #1

BASELINE OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		1	2	3	4	5	6	7	8	9	10
PURPOSE OF TEST		← EXCESS AIR VARIATION →									
UNIT LOAD CONDITION		Max	Max	Max	3/4 Max	1/2 Max	1/2 Max	1/2 Max	Max	Max	Max
FURNACE CONDITION		Clean	Clean	Clean	Clean	Clean	Clean	Clean	Moderately Dirty		
EXCESS AIR CONDITION		Min	Norm	Max	Norm	Min	Norm	Max	Min	Norm	Max
DATE	1976	3/10	3/8	3/15	3/13	5/23	5/23	5/23	3/10	3/9	3/10
UNIT LOAD	MW	524	524	485	399	324	323	322	514	515	482
MAIN STEAM FLOW	KG/S	441	442	400	334	267	269	268	427	432	394
SHO TEMPERATURE	°C	536	540	543	542	546	543	548	540	540	540
RHO TEMPERATURE	°C	541	542	541	539	522	521	522	541	541	544
FUEL ELEVATIONS IN SERVICE		ABDEF	ABDEF	ABDEF	ABDEF	CDEF	CDEF	CDEF	ABDEF	ABDEF	ABDEF
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0	0	0
FUEL NOZZLE TILT	DEG	-4	+1	-2	+17	+10	+10	+9	-4	+3	-4
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN: OFA	% OPEN	0	0	0	0	0	0	0	0	0	0
OFA	% OPEN	0	0	0	0	0	0	0	0	0	0
AUX	% OPEN	100	100	100	55	0	5	10	55	100	100
1-F FUEL	% OPEN	50	50	50	40	85	75	80	40	50	50
AUX	% OPEN	100	100	100	50	0	5	15	60	100	100
1-E FUEL	% OPEN	50	50	50	45	90	85	80	40	50	50
AUX	% OPEN	100	100	100	50	0	5	10	55	100	100
1-D FUEL	% OPEN	50	50	50	40	85	80	85	35	50	50
AUX	% OPEN	100	100	100	50	5	10	20	50	100	100
1-C FUEL	% OPEN	0	0	0	0	90	70	85	0	0	0
AUX	% OPEN	100	100	100	50	0	10	15	50	100	100
1-B FUEL	% OPEN	50	50	50	40	0	0	0	35	50	50
AUX	% OPEN	100	100	100	50	0	0	0	50	100	100
1-A FUEL	% OPEN	50	50	50	40	0	0	0	35	50	50
AUX	% OPEN	100	100	100	50	0	0	0	55	100	100
EXCESS AIR AT ECONOMIZER OUTLET	%	20.7	21.8	34.7	35.6	27.7	37.5	43.5	19.4	23.7	30.6
THEO. AIR TO THE FUEL FIRING ZONE	%	117.8	118.9	131.4	132.5	126.7	136.2	141.4	116.5	120.7	127.5
NO_x (ADJ. TO 0% O_2)	PPM	650	520	599	498	593	653	662	596	578	626
NO_x AS NO_2	NG/J	322.9	260.2	303.7	246.3	291.2	335.2	333.8	295.7	290.2	310.6
SO_2 (ADJ. TO 0% O_2)	PPM	1156	1138	1003	1119	1362	1379	1230	1184	1230	1171
SO_2	NG/J	799.7	792.6	708.4	770.4	931.8	985.0	864.0	817.9	859.4	809.1
CO (ADJ. TO 0% O_2)	PPM	16	16	18	NA	5	6	7	17	16	17
CO	NG/J	4.8	4.8	5.4	NA	1.5	1.7	2.2	5.1	4.9	5.1
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	3.6	3.8	5.5	5.6	4.6	5.8	6.4	3.5	4.1	5.0
O_2 AT A.H. INLET	%	4.3	4.4	5.7	5.7	4.9	6.0	6.5	4.0	4.5	5.2
O_2 AT A.H. OUTLET	%	4.5	5.3	6.8	7.6	7.2	7.6	8.1	4.2	5.6	5.6
CO_2 AT ECONOMIZER OUTLET	%	15.6	15.6	14.1	14.0	14.9	13.5	13.1	15.9	15.2	14.5
CO_2 AT A.H. INLET	%	15.0	15.1	13.9	13.9	14.6	13.3	13.0	15.4	14.8	14.2
CO_2 AT A.H. OUTLET	%	14.8	14.2	12.9	12.2	12.5	11.9	11.6	15.2	13.8	13.9
CARBON LOSS IN FLY ASH	%	0.02	0.03	0.02	0.04	0.03	0.02	0.02	0.02	0.02	0.11

BASELINE OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		11	12	13	14	15	16	17	18	19
PURPOSE OF TEST		EXCESS AIR VARIATION								
UNIT LOAD CONDITION		1/2 MAX	1/2 MAX	MAX	MAX	MAX	3/4 MAX	1/2 MAX	1/2 MAX	1/2 MAX
FURNACE CONDITION		MODERATE		DIRTY	DIRTY	DIRTY	DIRTY	DIRTY	DIRTY	DIRTY
EXCESS AIR CONDITION		MIN	MAX	MIN	NORM	MAX	NORM	MIN	NORM	MAX
DATE	1976	5/21	5/25	3/12	3/9	3/10	3/13	5/25	5/25	5/25
UNIT LOAD	MW	321	321	524	513	484	401	322	325	322
MAIN STEAM FLOW	KG/S	263	265	432	426	397	329	264	267	263
SHO TEMPERATURE	°C	546	546	543	539	540	542	545	545	546
RHO TEMPERATURE	°C	541	536	543	540	544	540	529	534	536
FUEL ELEVATIONS IN SERVICE		ABCD	ABCD	ABDEF	ABDEF	ABDEF	ABDEF	ABCD	ABCD	ABCD
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0	0
FUEL NOZZLE TILT	DEG	+10	+6	-4	+3	-4	+18	+7	+6	+7
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN: OFA	% OPEN	0	0	0	0	0	0	0	0	0
OFA	% OPEN	0	0	0	0	0	0	0	0	0
AUX	% OPEN	0	0	100	100	100	55	0	0	0
1-F FUEL	% OPEN	0	0	45	50	50	40	0	0	0
AUX	% OPEN	0	0	100	100	100	50	0	0	0
1-E FUEL	% OPEN	0	0	50	50	50	45	0	0	0
AUX	% OPEN	0	30	100	100	100	50	0	10	55
1-D FUEL	% OPEN	50	90	50	50	50	40	80	80	70
AUX	% OPEN	0	35	100	100	100	50	0	15	45
1-C FUEL	% OPEN	65	90	0	0	0	0	85	80	90
AUX	% OPEN	0	30	100	100	100	50	0	15	50
1-B FUEL	% OPEN	50	80	50	50	50	40	75	80	70
AUX	% OPEN	0	35	100	100	100	50	0	15	40
1-A FUEL	% OPEN	55	80	50	50	50	40	80	80	85
AUX	% OPEN	100	100	100	100	100	50	100	100	100
EXCESS AIR AT ECONOMIZER OUTLET	%	20.4	52.5	17.1	22.6	32.2	35.7	26.1	39.5	54.8
THEO. AIR TO THE FUEL FIRING ZONE	%	117.2	145.0	114.3	119.7	129.0	132.5	122.8	134.3	144.6
NO_x (ADJ. TO 0% O_2)	PPM	536	733	626	617	674	478	586	690	733
NO_x AS NO_2	NG/J	270.5	368.3	315.7	309.5	334.3	252.9	294.6	347.7	369.2
SO_2 (ADJ. TO 0% O_2)	PPM	1318	1131	1197	1070	1293	975	1250	1460	1140
SO_2	NG/J	925.4	791.8	839.8	747.0	891.1	718.5	875.4	1024.4	800.1
CO (ADJ. TO 0% O_2)	PPM	5	6	NA	16	19	NA	4	4	5
CO	NG/J	1.5	1.9	NA	4.9	5.6	NA	1.2	1.3	1.4
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	3.6	7.3	3.1	3.9	5.2	5.6	4.4	6.0	7.5
O_2 AT A.H. INLET	%	3.7	7.6	3.5	4.6	5.5	6.0	4.8	6.3	7.7
O_2 AT A.H. OUTLET	%	5.8	9.5	4.9	5.5	6.1	7.4	6.6	7.7	9.6
CO_2 AT ECONOMIZER OUTLET	%	15.6	12.3	16.2	15.5	14.3	14.0	15.1	13.6	12.2
CO_2 AT A.H. INLET	%	15.5	12.0	15.8	14.9	14.0	13.6	14.7	13.3	12.0
CO_2 AT A.H. OUTLET	%	13.6	10.3	14.5	14.0	13.5	12.3	13.0	12.0	10.3
CARBON LOSS IN FLY ASH	%	0.01	0.02	0.30	0.01	0.19	0.04	0.02	0.02	0.02

BIASED FIRING OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		1	2	3	4	5	6	7	8	9
PURPOSE OF TEST		← VARIATION OF FUEL ELEVATIONS IN SERVICE →								
UNIT LOAD CONDITION		MAXIMUM	MAXIMUM	MAXIMUM	MAXIMUM	3/4 MAX	3/4 MAX	3/4 MAX	1/2 MAX	1/2 MAX
EXCESS AIR CONDITION		MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM
FURNACE CONDITION		← MODERATELY DIRTY →								CLEAN
DATE	1976	5/19	5/19	3/14	5/19	5/12	5/12	5/16	5/21	6/27
UNIT LOAD	MW	505	506	525	506	422	422	421	320	314
MAIN STEAM FLOW	KG/S	426	428	433	431	352	352	344	263	258
SHO TEMPERATURE	°C	546	546	543	545	545	543	546	545	544
RHO TEMPERATURE	°C	550	547	542	548	544	545	547	545	504
FUEL ELEVATIONS IN SERVICE		ABCDE	ABCDF	ABDEF	BCDEF	ABCE	ABCE	BCDE	ABCD	ABEF
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0	0
FUEL NOZZLE TILT	DEG	+4	-4	-4	-8	-2	0	+13	+10	0
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN: OFA	% OPEN	0	0	0	0	0	0	0	0	0
OFA	% OPEN	0	0	0	0	0	0	0	0	0
AUX	% OPEN	0	30	90	35	0	0	0	0	0
1-F FUEL	% OPEN	100	100	50	100	100	0	0	100	90
AUX	% OPEN	45	35	90	35	20	20	25	0	0
1-E FUEL	% OPEN	100	100	50	100	100	100	100	100	90
AUX	% OPEN	45	30	90	30	20	10	20	0	0
1-D FUEL	% OPEN	100	100	50	100	0	100	100	85	100
AUX	% OPEN	45	30	90	30	15	15	15	0	0
1-C FUEL	% OPEN	100	100	95	100	100	100	100	90	100
AUX	% OPEN	45	25	90	30	15	15	15	0	0
1-B FUEL	% OPEN	100	100	40	100	100	100	90	90	80
AUX	% OPEN	45	35	80	30	10	15	10	0	0
1-A FUEL	% OPEN	100	100	50	100	100	100	100	90	80
AUX	% OPEN	50	45	95	0	100	100	100	100	80
EXCESS AIR AT ECONOMIZER OUTLET	%	20.4	18.4	15.2	19.0	26.1	21.7	30.7	19.7	34.2
THEO. AIR TO THE FUEL FIRING ZONE	%	108.2	116.6	112.6	116.9	110.0	117.5	125.6	94.4	133.5
NO_x (ADJ. TO 0% O_2)	PPM	408	413	492	504	417	507	442	326	513
NO_x AS NO_2	NG/J	203.9	209.1	249.2	250.3	215.9	260.2	227.3	162.2	245.1
SO_2 (ADJ. TO 0% O_2)	PPM	1152	1101	1170	NA	1088	1088	1088	1252	995
SO_2	NG/J	802.4	776.6	826.1	NA	783.6	778.1	778.6	865.9	662.2
CO (ADJ. TO 0% O_2)	PPM	NA	NA	NA	NA	25	13	143	5	4
CO	NG/J	NA	NA	NA	NA	8.0	4.2	44.8	1.4	1.2
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	3.6	3.3	2.8	3.4	4.4	3.8	5.0	3.5	5.4
O_2 AT A.H. INLET	%	4.0	4.0	3.3	4.0	4.7	4.2	5.2	3.7	5.6
O_2 AT A.H. OUTLET	%	6.3	6.2	4.7	6.1	6.8	5.9	6.6	6.0	7.6
CO_2 AT ECONOMIZER OUTLET	%	15.8	16.1	16.5	16.0	14.9	15.3	14.3	15.9	14.3
CO_2 AT A.H. INLET	%	15.4	15.4	16.0	15.4	14.6	14.9	14.1	15.7	14.1
CO2 AT A.H. OUTLET	%	13.3	13.4	14.7	13.5	12.7	13.4	12.8	13.6	12.2
CARBON LOSS IN FLY ASH	%	0.02	0.03	0.35	0.02	0.03	0.02	0.02	0.01	0.02

BIASED FIRING OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		10	11	12	13	14	15	16	17	18
PURPOSE OF TEST		← VARIATION OF FUEL ELEVATIONS IN SERVICE →								
UNIT LOAD CONDITION		1/2 MAX	MAXIMUM	MAXIMUM	MAXIMUM	3/4 MAX	3/4 MAX	3/4 MAX	1/2 MAX	1/2 MAX
EXCESS AIR CONDITION		MINIMUM	NORMAL	NORMAL	NORMAL	NORMAL	NORMAL	NORMAL	NORMAL	NORMAL
FURNACE CONDITION		CLEAN	← MODERATELY DIRTY →							CLEAN
DATE	1976	5/23	5/19	5/10	3/16	5/12	3/13	5/16	5/21	5/23
UNIT LOAD	MW	324	491	497	523	423	400	422	320	323
MAIN STEAM FLOW	KG/S	268	417	417	438	353	325	350	261	264
SHO TEMPERATURE	°C	547	546	547	542	545	543	546	545	545
RHO TEMPERATURE	°C	529	550	546	542	544	540	547	543	530
FUEL ELEVATIONS IN SERVICE		CDEF	ABCDF	ABCEF	ABDEF	ABCE	ABDEF	BCDE	ABCD	CDEF
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0	0
FUEL NOZZLE TILT	DEG	+5	+5	-2	-4	0	0	+10	+12	+9
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN										
OFA	% OPEN	0	0	0	0	0	0	0	0	0
OFA	% OPEN	0	0	0	0	0	0	0	0	0
AUX	% OPEN	0	0	15	95	0	55	0	0	0
1-F FUEL	% OPEN	55	100	100	50	100	40	0	100	85
AUX	% OPEN	0	50	35	95	30	50	35	0	0
1-E FUEL	% OPEN	65	100	100	50	100	45	100	100	90
AUX	% OPEN	0	45	30	90	35	50	35	0	0
1-D FUEL	% OPEN	55	100	100	50	0	35	100	90	80
AUX	% OPEN	0	40	35	95	30	50	40	0	0
1-C FUEL	% OPEN	60	100	100	50	100	100	100	90	90
AUX	% OPEN	0	45	30	95	25	50	35	0	0
1-B FUEL	% OPEN	90	100	95	100	100	40	100	90	100
AUX	% OPEN	0	50	30	85	20	50	50	0	0
1-A FUEL	% OPEN	100	100	100	50	100	40	100	70	100
AUX	% OPEN	0	50	100	95	100	50	100	100	0
EXCESS AIR AT ECONOMIZER OUTLET	%	29.2	23.1	24.6	18.4	34.1	35.8	41.3	35.9	36.6
THEO. AIR TO THE FUEL FIRING ZONE	%	128.4	122.7	123.4	115.8	117.9	132.9	135.8	105.8	135.8
NO_x (ADJ. TO 0% O_2)	PPM	525	454	590	556	443	462	494	462	629
NO_x AS NO_2	NG/J	266.8	231.2	297.2	280.4	222.5	231.7	246.4	228.7	316.9
SO_2 (ADJ. TO 0% O_2)	PPM	1313	1174	870	1029	1139	859	1166	1256	1278
SO_2	NG/J	929.3	831.0	610.3	721.9	796.9	599.6	810.7	865.4	897.1
CO (ADJ. TO 0% O_2)	PPM	5	NA	18	NA	74	NA	NA	4	7
CO	NG/J	1.6	NA	5.4	NA	22.6	NA	NA	1.2	2.1
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	4.8	4.0	4.2	3.3	5.4	5.6	6.2	5.6	5.7
O_2 AT A.H. INLET	%	5.2	4.1	4.8	4.3	5.7	5.7	6.4	5.8	5.9
O_2 AT A.H. OUTLET	%	6.9	6.7	6.2	5.6	7.1	7.4	8.4	7.6	7.8
CO_2 AT ECONOMIZER OUTLET	%	14.5	15.3	15.2	16.1	14.1	13.8	13.4	13.9	13.6
CO_2 AT A.H. INLET	%	14.2	15.2	14.7	15.2	13.8	13.8	13.2	13.7	13.4
CO_2 AT A.H. OUTLET	%	12.6	12.8	13.4	13.9	12.5	12.1	11.4	12.1	11.7
CARBON LOSS IN FLY ASH	%	0.04	0.02	0.03	0.03	0.02	0.02	0.02	0.02	0.04

OVERFIRE AIR OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12
PURPOSE OF TEST		← OVERFIRE AIR DAMPER VARIATION →											TILT VAR. WITH OFA
UNIT LOAD CONDITION		MAXIMUM NORMAL	MAXIMUM NORMAL	MAXIMUM NORMAL	MAXIMUM NORMAL	MAXIMUM NORMAL	MAXIMUM MINIMUM	MAXIMUM MINIMUM	MAXIMUM MINIMUM	MAXIMUM MAXIMUM MODERATE	MAXIMUM MAXIMUM	MAXIMUM MAXIMUM	MAXIMUM MINIMUM
EXCESS AIR CONDITION						← CLEAN →							
FURNACE CONDITION		← MODERATELY DIRTY →											
DATE	1976	3/17	3/17	3/20	3/20	3/22	3/20	3/20	3/20	3/24	3/24	3/24	6/24
UNIT LOAD	MW	517	512	524	525	526	521	522	522	476	473	472	524
MAIN STEAM FLOW	KG/S	425	426	439	445	444	446	441	439	398	390	389	446
SHO TEMPERATURE	°C	542	541	533	534	534	543	532	532	538	539	534	540
RHO TEMPERATURE	°C	542	541	534	533	538	547	534	532	540	540	539	547
FUEL ELEVATIONS IN SERVICE		ACDEF	ACDEF	ACDEF	ACDEF	ACDEF	ACDEF	ACDEF	ACDEF	ABCEF	ABCEF	ABCEF	ABDEF
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0	0	0	0	-5
FUEL NOZZLE TILT	DEG	-4	-4	-8	+1	+1	+6	+8	+1	+2	+1	+3	-5
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN: OFA	% OPEN	0	25	50	70	95	0	50	100	25	80	100	100
OFA	% OPEN	0	25	50	70	95	0	50	100	25	80	100	100
AUX	% OPEN	100	95	85	75	65	65	55	50	100	80	55	25
1-F FUEL	% OPEN	50	50	50	50	50	50	50	50	50	50	50	100
AUX	% OPEN	100	100	85	75	65	65	50	50	90	75	50	20
1-E FUEL	% OPEN	50	50	50	50	50	50	50	50	50	50	50	100
AUX	% OPEN	100	95	85	75	70	65	55	50	90	80	50	20
1-D FUEL	% OPEN	50	50	50	50	50	50	50	50	0	0	0	100
AUX	% OPEN	100	100	80	70	60	60	50	50	95	80	50	20
1-C FUEL	% OPEN	50	50	50	50	50	50	50	50	50	50	45	0
AUX	% OPEN	100	95	85	70	70	65	55	50	95	75	50	15
1-B FUEL	% OPEN	0	0	0	0	0	0	0	0	50	50	50	100
AUX	% OPEN	100	95	80	70	65	60	50	50	90	80	50	20
1-A FUEL	% OPEN	50	50	50	50	50	50	50	50	50	50	50	100
AUX	% OPEN	100	95	85	70	70	75	70	50	100	90	85	100
EXCESS AIR AT ECONOMIZER OUTLET	%	23.9	23.2	21.8	19.7	20.4	13.3	13.9	15.1	36.8	35.8	30.0	23.9
THEO. AIR TO THE FUEL FIRING ZONE	%	120.9	115.7	109.7	105.2	104.6	110.7	101.8	99.0	128.2	118.8	111.5	102.8
NO_x (ADJ. TO 0% O_2)	PPM	718	710	442	409	434	364	356	344	594	551	485	395
NO_x AS NO_2	NG/J	356.1	354.9	222.8	203.4	215.4	182.7	177.9	171.4	299.2	274.7	246.5	195.5
SO_2 (ADJ. TO 0% O_2)	PPM	1190	1207	1266	1404	1320	1203	1245	1240	1267	1342	1329	1023
SO_2	NG/J	821.9	839.8	888.8	971.9	911.8	840.2	866.5	861.0	888.3	931.8	940.3	704.7
CO (ADJ. TO 0% O_2)	PPM	16	16	NA	NA	NA	NA	NA	NA	NA	NA	NA	16
CO	NG/J	4.9	4.9	NA	NA	NA	NA	NA	NA	NA	NA	NA	4.9
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	4.1	4.0	3.8	3.5	3.6	2.5	2.6	2.8	5.7	5.6	4.9	4.1
O_2 AT A.H. INLET	%	4.3	5.0	4.0	3.9	4.1	3.3	3.4	3.5	5.8	5.8	5.0	4.4
O_2 AT A.H. OUTLET	%	5.3	5.4	5.3	5.1	5.0	4.5	5.0	4.5	7.0	7.0	6.1	5.6
CO_2 AT ECONOMIZER OUTLET	%	15.3	15.4	15.5	15.8	15.7	16.7	16.6	16.4	13.9	13.8	13.5	13.9
CO_2 AT A.H. INLET	%	15.1	14.5	15.3	15.4	15.2	16.0	15.9	15.8	13.8	13.7	14.5	15.0
CO_2 AT A.H. OUTLET	%	14.2	14.2	14.1	14.4	14.4	14.9	14.4	14.9	12.7	12.6	13.5	13.9
CARBON LOSS IN FLY ASH	%	0.01	0.02	0.02	0.01	0.02	0.03	0.04	0.03	0.01	0.02	0.01	0.02

OVERFIRE AIR OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		13	14	15	16	17	18	19	20	21	22	23	24
PURPOSE OF TEST		← FUEL NOZZLE - OFA NOZZLE TILT VARIATION →							← OPTIMUM OFA OPERATION →				
UNIT LOAD CONDITION		MAXIMUM	MAXIMUM	MAXIMUM	MAXIMUM	MAXIMUM	MAXIMUM	MAXIMUM	MAXIMUM	3/4 MAX	3/4 MAX	1/2 MAX	1/2 MAX
EXCESS AIR CONDITION		MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM	MINIMUM
FURNACE CONDITION		MODERATE	←	CLEAN	→	MODERATE	CLEAN	MODERATE	HEAVY	CLEAN	MODERATE	CLEAN	MODERATE
DATE	1976	6/24	6/24	3/25	6/30	6/25	6/30	6/29	6/25	6/26	6/25	6/27	5/29
UNIT LOAD	MW	525	523	511	526	524	526	524	521	419	422	316	322
MAIN STEAM FLOW	KG/S	444	443	425	438	440	441	441	438	350	342	263	259
SHO TEMPERATURE	°C	548	544	533	548	547	548	546	548	546	548	538	546
RHO TEMPERATURE	°C	539	546	536	545	547	542	547	542	542	545	500	543
FUEL ELEVATIONS IN SERVICE		ABDEF	ABDEF	ABCEF	ABDEF	ABDEF	ABDEF	ABDEF	ABDEF	ABDE	ABDEF	ABEF	ABEF
OFA NOZZLE TILT	DEG	-5	0	0	0	+30	+30	+10	0	0	0	+10	+10
FUEL NOZZLE TILT	DEG	0	-5	+1	26	+2	+26	+1	0	0	0	+7	+12
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN													
	OFA	100	100	100	100	100	100	100	100	100	100	100	100
	OFA	100	100	100	100	100	100	100	100	100	100	100	100
	AUX	20	25	50	20	25	20	10	20	0	0	0	0
1-F	FUEL	100	95	50	100	100	100	100	90	0	100	80	0
	AUX	20	30	50	20	20	20	10	5	10	0	0	0
1-E	FUEL	100	100	50	100	100	100	100	90	100	100	85	85
	AUX	20	20	50	20	20	20	10	5	5	0	0	0
1-D	FUEL	100	100	0	100	100	100	100	70	100	100	0	80
	AUX	20	25	50	20	20	20	10	5	10	0	0	5
1-C	FUEL	0	0	50	0	0	0	0	0	0	0	0	0
	AUX	20	20	50	20	15	20	5	5	0	0	85	80
1-B	FUEL	100	100	50	100	100	100	100	100	100	100	0	0
	AUX	20	15	50	20	20	20	10	5	0	0	0	0
1-A	FUEL	100	100	50	100	100	100	100	100	100	100	85	80
	AUX	100	100	50	100	100	100	100	100	100	100	90	80
EXCESS AIR AT ECONOMIZER OUTLET	%	26.9	26.9	18.3	24.6	26.2	23.2	19.1	25.4	30.0	28.5	32.5	34.2
THEO. AIR TO THE FUEL FIRING ZONE	%	105.7	106.0	101.5	103.9	104.7	103.1	99.7	99.3	98.6	103.4	106.1	107.0
NO_x (ADJ. TO 0% O_2)	PPM	428	389	392	558	460	473	385	483	340	456	341	334
NO_x AS NO_2	NG/J	205.4	188.5	198.9	273.7	224.6	223.4	182.8	234.8	171.8	220.6	161.9	161.0
SO_2 (ADJ. TO 0% O_2)	PPM	1008	937	1010	958	964	981	941	958	905	989	959	1069
SO_2	NG/J	674.2	631.4	714.2	654.7	654.8	645.0	621.9	648.9	636.3	656.4	634.0	717.8
CO (ADJ. TO 0% O_2)	PPM	5	10	NA	8	15	59	76	4	4	4	4	5
CO	NG/J	1.5	3.0	NA	2.2	4.5	17.0	22.1	1.1	1.2	1.1	1.2	1.6
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	4.5	4.5	3.3	4.2	4.4	4.0	3.4	4.3	4.9	4.7	5.3	5.4
O_2 AT A.H. INLET	%	4.7	4.6	3.6	4.4	4.7	4.2	3.5	4.6	5.2	4.9	5.5	5.4
O_2 AT A.H. OUTLET	%	6.2	5.9	5.0	5.7	6.1	5.8	5.0	6.0	6.9	6.3	7.2	7.1
CO_2 AT ECONOMIZER OUTLET	%	13.5	13.8	14.4	13.9	13.6	13.9	14.7	13.7	14.6	14.9	14.5	14.2
CO_2 AT A.H. INLET	%	14.9	15.0	15.6	15.0	14.9	15.4	16.1	15.0	14.3	14.7	14.2	14.2
CO_2 AT A.H. OUTLET	%	13.5	13.8	14.4	13.9	13.6	13.9	14.7	13.7	12.7	13.4	12.6	12.6
CARBON LOSS IN FLY ASH	%	0.02	0.02	0.01	0.06	0.05	0.05	0.03	0.03	0.02	0.02	0.03	0.02

BASELINE OPERATION STUDY

TEST DATA

TEST NO.		1	2	3	4	5	6	7	8	9	10
Date	1976	3/10	3/08	3/15	3/13	5/23	5/23	5/23	3/10	3/09	3/10
Unit Load	MW	524	524	485	399	324	323	322	514	515	482
FLOWS	kg/s										
Feedwater		411.51	430.91	380.51	324.19	262.45	264.72	262.45	397.02	405.84	371.19
PRESSURES (GAUGE)	MPa										
Economizer Inlet		18.664	18.781	18.409	17.878	17.492	17.499	17.492	18.574	18.630	18.333
Drum		18.271	18.326	18.078	17.582	17.278	17.251	17.264	18.202	18.230	18.009
SH Outlet		16.892	16.878	16.872	16.706	16.699	16.685	16.706	16.865	16.885	16.802
Turbine 1st Stage		11.232	11.321	10.163	8.246	6.433	6.440	6.440	10.901	10.956	10.080
RH Inlet		3.654	3.634	3.330	2.641	2.068	2.068	2.068	3.571	3.578	3.302
RH Outlet		3.447	3.413	3.151	2.489	1.896	1.896	1.889	3.372	3.385	3.110
SH Spray Water		18.457	19.809	19.009	18.850	18.843	18.871	18.809	18.395	19.684	18.312
RH Spray Water		10.052	10.122	9.908	9.542	9.329	9.336	9.329	9.991	10.011	9.853
HP HTR's G1&G2 Stm In		3.606	3.606	3.323	2.627	2.068	2.068	2.062	3.558	3.572	3.303
TEMPERATURES	°C										
Water and Steam											
Economizer Inlet		247	247	243	230	219	219	219	247	246	243
Economizer Outlet	L	344	337	344	333	317	321	323	344	344	347
Economizer Outlet	LC	343	333	342	328	312	317	317	343	341	343
Economizer Outlet	RC	NA	NA	NA	NA	317	320	321	NA	NA	NA
Economizer Outlet	R	350	345	348	332	318	326	327	352	350	351
SH Pend Div Inlet Link	L	384	378	388	383	381	382	382	387	384	389
SH Pend Div Inlet Link	R	390	386	392	383	382	383	383	393	391	395
SH Desh Outlet Link	L	414	421	417	418	435	434	437	414	413	413
SH Desh Outlet Link	R	404	421	415	417	431	428	432	408	412	413
SH Pend Spcd Front In Link	L	496	498	497	507	518	513	521	496	497	496
SH Pend Spcd Front In Link	R	482	490	490	499	507	501	509	482	484	484
SH Outlet Leads	L	539	538	542	543	547	545	550	543	542	543
SH Outlet Leads	R	533	543	544	542	546	541	547	538	538	538
RH Desh Inlet Comb. Line		319	321	316	298	283	280	283	321	322	314
RH Radiant Wall Front In HDR	L	275	292	268	298	283	280	283	261	269	279
RH Radiant Wall Front In HDR	R	267	283	272	297	282	280	285	263	267	268
RH Pend Spcd Front In Links	L	309	323	306	331	318	312	314	304	308	313
RH Pend Spcd Front In Links	LC	308	320	307	329	317	312	316	303	304	312
RH Pend Spcd Front In Links	RC	312	317	312	NA	318	313	316	308	309	309
RH Pend Spcd Front In Links	R	303	308	301	319	307	304	310	300	299	301
RH Outlet Leads	L	531	531	536	545	523	517	516	531	531	541
RH Outlet Leads	R	552	553	547	532	522	526	529	552	551	547
SH Spray Water		173	173	171	159	156	154	155	173	172	168
RH Spray Water		183	182	179	151	96	91	87	193	182	179
Cold RH Ext Stm to G1&G2 HTR		328	328	323	306	288	287	291	329	327	322
FW In to HP HTR G1		207	206	203	192	184	184	184	206	205	203
FW In to HP HTR G2		206	205	202	191	184	184	184	206	204	202
FW Out of HP HTR G1		247	247	242	228	219	218	218	247	246	242
FW Out of HP HTR G2		247	246	242	229	218	219	218	246	246	242
Stm Drain from HP HTR G1		212	211	208	195	187	187	187	212	211	207
Stm Drain from HP HTR G2		208	208	205	193	187	186	186	208	208	204
Air & Gas											
Pri Air AH Air Inlet	L	9	4	4	2	27	27	26	10	7	9
Pri Air AH Air Inlet	R	5	3	4	0	23	23	23	7	5	7
Sec Air AH Air Inlet	L	16	22	20	34	37	38	36	16	17	17
Sec Air AH Air Inlet	R	15	23	21	33	36	37	36	14	18	16
Pri Air AH Air Outlet	L	369	354	364	329	311	302	306	371	366	369
Pri Air AH Air Outlet	R	374	361	369	328	303	305	309	378	371	374
Sec Air AH Air Outlet	L	361	346	354	323	303	302	302	363	357	360
Sec Air AH Air Outlet	R	362	349	353	320	298	301	302	366	359	363
Economizer Gas Outlet	L	418	402	409	371	339	346	346	416	411	413
Economizer Gas Outlet	R	431	413	422	379	341	349	351	432	427	427
AH Gas Inlet	L	398	383	395	355	322	327	328	398	396	396
AH Gas Inlet	R	409	392	401	357	324	331	333	411	403	406
AH Gas Outlet	L	122	111	118	110	117	118	118	123	117	122
AH Gas Outlet	R	119	119	118	106	101	101	101	121	119	119

BASELINE OPERATION STUDY

TEST DATA

TEST NO.		11	12	13	14	15	16	17	18	19
Date	1976	5/21	5/25	3/12	3/09	3/10	3/13	5/25	5/25	5/25
Unit Load	MW	321	321	524	513	484	401	322	325	322
FLOWS	kg/s									
Feedwater		236.75	248.84	402.94	408.74	371.19	322.43	246.45	246.45	244.06
PRESSURES (GAUGE)	MPa									
Economizer Inlet		17.347	17.423	18.623	18.643	18.312	17.906	17.430	17.423	17.409
Drum		17.154	17.196	18.230	18.244	17.968	17.623	17.223	17.237	17.196
SH Outlet		16.685	16.678	16.878	16.899	16.816	16.741	16.727	16.720	16.692
Turbine 1st Stage		6.295	6.336	11.114	10.928	10.087	8.267	6.274	6.343	6.357
RH Inlet		2.075	2.068	3.661	3.564	3.309	2.654	2.075	2.096	2.082
RH Outlet		1.903	1.889	3.461	3.365	3.137	2.503	1.903	1.931	1.910
SH Spray Water		18.354	18.312	19.595	19.354	19.264	19.030	18.278	18.085	18.182
RH Spray Water		9.198	9.341	10.011	10.025	9.846	9.563	9.218	9.239	9.308
HP HTR's G1&G2 Stm In		2.082	2.075	3.654	3.551	3.310	2.641	2.075	2.103	2.089
TEMPERATURES	°C									
Water and Steam										
Economizer Inlet		220	219	248	246	243	231	220	221	219
Economizer Outlet	L	331	338	348	344	346	331	327	337	343
Economizer Outlet	LC	328	331	346	344	342	327	322	337	343
Economizer Outlet	RC	332	334	NA	NA	NA	NA	328	336	339
Economizer Outlet	R	332	344	349	349	352	330	330	341	348
SH Pend Div Inlet Link	L	391	392	391	386	389	381	387	392	393
SH Pend Div Inlet Link	R	392	396	393	393	393	382	389	395	398
SH Desh Outlet Link	L	413	427	415	419	411	421	427	425	427
SH Desh Outlet Link	R	410	423	413	417	408	418	423	421	423
SH Pend Spcd Front In Link	L	509	508	496	494	499	507	512	508	507
SH Pend Spcd Front In Link	R	494	499	489	482	487	501	496	494	496
SH Outlet Leads	L	551	545	544	539	542	543	548	548	547
SH Outlet Leads	R	541	547	542	539	537	542	542	543	546
RH Desh Inlet Comb. Line		283	282	327	321	315	297	283	283	283
RH Radiant Wall Front In HDR	L	257	274	256	269	273	296	265	266	270
RH Radiant Wall Front In HDR	R	244	266	268	266	261	297	249	249	256
RH Pend Spcd Front In Links	L	306	309	301	308	311	330	306	304	306
RH Pend Spcd Front In Links	LC	301	304	304	304	308	328	302	298	302
RH Pend Spcd Front In Links	RC	299	301	316	307	304	327	295	292	296
RH Pend Spcd Front In Links	R	285	293	308	300	296	319	283	281	287
RH Outlet Leads	L	546	527	544	533	541	545	528	530	528
RH Outlet Leads	R	536	545	542	548	547	536	531	538	543
SH Spray Water		156	155	176	173	169	158	156	156	156
RH Spray Water		162	162	184	182	179	129	163	163	163
Cold RH Ext Stm to G1&G2 HTR		291	289	333	327	322	306	290	290	289
FW In to HP HTR G1		186	184	207	205	202	192	185	186	186
FW In to HP HTR G2		185	184	206	204	202	191	184	185	184
FW Out of HP HTR G1		219	218	248	245	242	229	218	219	218
FW Out of HP HTR G2		219	218	248	246	242	229	219	220	219
Stm Drain from HP HTR G1		188	186	213	209	207	196	188	188	188
Stm Drain from HP HTR G2		187	186	209	207	204	193	187	187	187
Air & Gas										
Pri Air AH Air Inlet	L	22	28	11	8	6	6	29	29	29
Pri Air AH Air Inlet	R	21	24	9	6	4	2	27	27	26
Sec Air AH Air Inlet	L	33	35	14	14	17	29	34	34	36
Sec Air AH Air Inlet	R	33	34	13	13	17	30	34	33	35
Pri Air AH Air Outlet	L	315	323	377	376	366	332	313	321	324
Pri Air AH Air Outlet	R	320	330	383	382	373	331	322	327	331
Sec Air AH Air Outlet	L	313	317	369	367	357	326	311	317	318
Sec Air AH Air Outlet	R	315	321	372	371	361	323	316	319	322
Economizer Gas Outlet	L	351	363	422	425	412	372	350	361	368
Economizer Gas Outlet	R	357	370	417	437	427	425	357	368	376
AH Gas Inlet	L	337	347	406	405	393	357	336	344	349
AH Gas Inlet	R	340	355	413	416	405	359	343	352	358
AH Gas Outlet	L	120	119	126	120	120	109	118	119	121
AH Gas Outlet	R	121	114	119	123	119	107	116	114	111

BIASED FIRING OPERATION STUDY

TEST DATA

TEST NO.		1	2	3	4	5	6	7	8	9
Date	1976	5/19	5/19	3/14	5/19	5/12	5/12	5/16	5/21	6/27
Unit Load	MW	505	506	525	506	422	422	421	320	314
FLOWS	kg/s									
Feedwater		405.84	411.51	404.33	404.33	348.51	345.11	341.71	236.75	255.78
PRESSURES (GAUGE)	MPa									
Economizer Inlet		18.636	18.643	18.636	18.588	18.043	18.023	18.037	17.306	17.471
Drum		18.237	18.223	18.244	18.175	17.713	17.713	17.713	17.134	17.306
SH Outlet		16.968	16.913	16.865	16.920	16.761	16.789	16.782	16.665	16.720
Turbine 1st Stage		10.942	10.908	11.101	10.894	8.791	8.756	8.818	6.295	6.460
RH Inlet		3.516	3.537	3.661	3.509	2.806	2.792	2.799	2.068	2.027
RH Outlet		3.254	3.268	3.454	3.261	2.579	2.692	2.586	1.903	1.855
SH Spray Water		19.891	20.016	19.650	19.774	19.429	19.292	19.250	18.306	18.974
RH Spray Water		10.115	10.108	10.018	10.073	9.722	9.715	9.742	9.191	9.329
HP HTR's G1&G2 Stm In		3.482	3.509	3.647	3.482	2.779	2.786	2.792	2.075	NA
TEMPERATURES	°C									
Water and Steam										
Economizer Inlet		247	247	248	248	235	234	234	220	216
Economizer Outlet	L	345	349	348	351	332	331	331	330	308
Economizer Outlet	LC	340	339	347	340	329	324	324	326	308
Economizer Outlet	RC	347	347	NA	347	335	329	333	331	312
Economizer Outlet	R	353	346	351	349	336	333	340	332	312
SH Pend Div Inlet Link	L	384	386	390	386	382	381	382	389	378
SH Pend Div Inlet Link	R	392	388	397	389	386	383	389	392	380
SH Desh Outlet Link	L	423	424	418	418	432	427	432	410	436
SH Desh Outlet Link	R	420	422	414	416	426	423	427	408	434
SH Pend Spcd Front In Link	L	504	504	492	496	507	510	506	509	519
SH Pend Spcd Front In Link	R	499	492	489	502	499	501	508	497	514
SH Outlet Leads	L	543	549	542	539	546	544	539	548	546
SH Outlet Leads	R	549	543	544	552	545	543	553	543	542
RH Desh Inlet Comb. Line		326	327	326	326	306	302	304	284	278
RH Radiant Wall Front In HDR	L	292	277	257	292	305	303	305	266	277
RH Radiant Wall Front In HDR	R	284	277	268	287	304	304	305	253	278
RH Pend Spcd Front In Links	L	327	310	298	318	334	335	340	309	306
RH Pend Spcd Front In Links	LC	324	312	302	319	332	333	333	304	306
RH Pend Spcd Front In Links	RC	323	318	316	322	332	332	333	299	309
RH Pend Spcd Front In Links	R	315	310	310	316	325	326	329	287	299
RH Outlet Leads	L	534	543	542	544	540	542	528	547	500
RH Outlet Leads	R	566	552	542	553	548	548	566	543	508
SH Spray Water		178	178	174	179	171	169	167	156	40
RH Spray Water		184	185	183	185	118	120	99	163	82
Cold RH Ext Stm to G1&G2 HTR		329	331	333	330	308	308	309	290	284
FW Into HP HTR G1		208	208	207	208	197	197	198	184	64
FW Into HP HTR G2		207	207	206	207	197	197	197	185	179
FW Out of HP HTR G1		247	247	248	247	234	234	234	219	88
FW Out of HP HTR G2		248	247	248	247	234	235	235	219	216
Stm Drain from HP HTR G1		213	213	213	213	202	201	202	187	47
Stm Drain from HP HTR G2		210	210	210	211	199	199	199	187	183
Air & Gas										
Pri Air AH Air Inlet	L	32	31	11	27	24	21	24	24	36
Pri Air AH Air Inlet	R	32	31	10	26	23	20	22	22	31
Sec Air AH Air Inlet	L	34	33	15	30	33	33	31	31	36
Sec Air AH Air Inlet	R	34	33	14	29	33	34	30	29	34
Pri Air AH Air Outlet	L	369	369	382	368	340	334	334	318	293
Pri Air AH Air Outlet	R	383	373	391	368	346	340	342	323	300
Sec Air AH Air Outlet	L	361	363	375	361	333	329	327	316	232
Sec Air AH Air Outlet	R	371	363	379	359	336	331	332	317	292
Economizer Gas Outlet	L	418	418	436	417	389	381	379	354	284
Economizer Gas Outlet	R	433	422	446	421	391	383	387	354	328
AH Gas Inlet	L	396	397	411	395	367	360	359	338	314
AH Gas Inlet	R	412	403	421	398	372	364	368	342	320
AH Gas Outlet	L	143	145	137	142	122	120	119	123	111
AH Gas Outlet	R	147	142	134	138	123	121	121	123	112

BIASED FIRING OPERATION STUDY

TEST DATA

TEST NO.		10	11	12	13	14	15	16	17	18
Date	1976	5/23	5/19	5/10	3/16	5/12	3/13	5/16	5/21	5/23
Unit Load	MW	324	491	497	523	423	400	422	320	323
FLOWS	kg/s									
Feedwater		260.31	391.10	383.66	407.22	348.51	320.54	345.11	234.23	253.51
PRESSURES (GAUGE)	MPa									
Economizer Inlet		17.458	18.506	18.464	18.671	18.078	17.892	18.064	17.361	17.478
Drum		17.223	18.154	18.244	18.257	17.768	17.616	17.733	17.161	16.858
SH Outlet		16.678	16.947	16.872	16.892	16.858	16.741	16.789	16.692	16.672
Turbine 1st Stage		6.433	10.480	10.597	11.232	8.805	8.225	8.811	6.316	6.419
RH Inlet		2.068	3.413	3.475	3.661	2.813	2.634	2.806	2.061	2.068
RH Outlet		1.896	3.165	3.199	3.468	2.606	2.489	2.599	1.896	1.896
SH Spray Water		18.761	18.816	19.347	19.629	19.422	19.036	19.236	18.361	18.657
RH Spray Water		9.308	10.025	9.991	10.039	9.763	9.556	9.756	9.218	9.301
HP HTR's G1&G2 Stm In		2.068	3.385	3.440	3.647	2.799	2.627	2.799	2.068	2.068
TEMPERATURES	°C									
Water and Steam										
Economizer Inlet		220	245	247	248	234	229	235	219	220
Economizer Outlet	L	318	348	352	346	337	328	336	334	323
Economizer Outlet	LC	313	342	346	343	334	324	332	331	318
Economizer Outlet	RC	316	348	349	NA	338	NA	340	336	322
Economizer Outlet	R	323	357	357	351	341	331	349	341	327
SH Pend Div Inlet Link	L	381	387	392	386	385	379	383	391	383
SH Pend Div Inlet Link	R	385	393	397	393	389	384	394	395	387
SH Desh Outlet Link	L	435	420	413	413	432	423	433	409	431
SH Desh Outlet Link	R	427	416	409	411	424	419	425	407	427
SH Pend Spcd Front In Link	L	517	500	505	494	504	504	502	508	510
SH Pend Spcd Front In Link	R	507	501	491	493	497	504	504	501	507
SH Outlet Leads	L	548	538	548	537	546	540	536	544	543
SH Outlet Leads	R	547	554	546	548	545	547	556	546	548
RH Desh Inlet Comb. Line		283	324	328	326	304	295	303	283	283
RH Radiant Wall Front In HDR	L	284	287	265	264	303	298	304	271	283
RH Radiant Wall Front In HDR	R	284	278	269	272	304	298	304	262	283
RH Pend Spcd Front In Links	L	320	324	308	307	331	329	339	315	318
RH Pend Spcd Front In Links	LC	318	320	308	308	328	325	332	306	317
RH Pend Spcd Front In Links	RC	316	319	316	319	328	326	333	300	314
RH Pend Spcd Front In Links	R	308	309	307	308	321	324	328	289	307
RH Outlet Leads	L	521	533	531	529	542	535	524	542	524
RH Outlet Leads	R	537	567	561	556	547	544	571	544	536
SH Spray Water		157	176	179	174	169	160	168	155	155
RH Spray Water		101	182	183	184	173	119	93	163	107
Cold RH Ext Stm to G1&G2 HTR		290	327	332	331	309	306	310	289	289
FW Into HP HTR G1		185	207	208	208	198	192	198	185	184
FW Into HP HTR G2		184	206	207	207	197	191	197	184	184
FW Out of HP HTR G1		219	245	246	248	235	229	234	218	218
FW Out of HP HTR G2		219	245	247	248	235	229	235	218	219
Stm Drain from HP HTR G1		187	211	212	212	202	195	201	187	187
Stm Drain from HP HTR G2		186	208	210	209	200	193	200	187	186
Air & Gas										
Pri Air AH Air Inlet	L	26	31	27	3	27	5	24	25	22
Pri Air AH Air Inlet	R	22	32	28	-1	26	4	22	24	19
Sec Air AH Air Inlet	L	38	34	29	18	29	29	30	30	41
Sec Air AH Air Inlet	R	37	33	29	18	30	29	29	29	41
Pri Air AH Air Outlet	L	300	371	376	370	347	331	340	327	295
Pri Air AH Air Outlet	R	305	381	389	377	353	334	351	334	296
Sec Air AH Air Outlet	L	298	362	367	361	339	325	332	322	291
Sec Air AH Air Outlet	R	299	369	376	364	342	325	339	327	289
Economizer Gas Outlet	L	342	419	426	427	397	378	389	361	348
Economizer Gas Outlet	R	344	431	437	434	399	380	403	362	349
AH Gas Inlet	L	321	398	404	399	376	357	367	347	319
AH Gas Inlet	R	326	410	418	409	381	361	381	354	322
AH Gas Outlet	L	116	144	137	129	122	118	124	126	112
AH Gas Outlet	R	118	142	134	112	123	114	123	127	109

OVERFIRE AIR OPERATION STUDY

TEST DATA

TEST NO.		1	2	3	4	5	6	7	8
Date	1976	3/17	3/17	3/20	3/20	3/22	3/20	3/20	3/20
Unit Load	MW	517	512	524	525	526	521	522	522
FLOWS	kg/s								
Feedwater		398.53	400.04	432.30	432.30	419.95	444.27	437.72	434.94
PRESSURES	MPa								
Economizer Inlet		18.581	18.588	18.802	18.788	18.733	18.892	18.850	18.830
Drum		18.216	18.188	18.354	18.319	18.299	18.409	18.409	18.361
SH Outlet		16.920	16.892	16.920	16.913	16.927	16.913	16.940	16.920
Turbine 1st Stage		10.908	10.845	11.356	11.300	11.356	11.356	11.300	9.915
RH Inlet		3.585	3.572	3.640	3.654	3.675	3.627	3.634	3.640
RH Outlet		3.392	3.378	3.426	3.440	3.461	3.385	3.413	3.420
SH Spray Water		19.588	19.671	20.022	19.760	18.823	20.319	20.105	20.016
RH Spray Water		9.963	9.950	10.163	10.129	10.136	10.239	10.177	10.163
HP HTR's G1&G2 Stm In		3.523	3.509	3.572	3.592	3.606	3.530	3.558	3.572
TEMPERATURES	°C								
Water & Steam									
Economizer Inlet		247	247	241	241	242	246	239	241
Economizer Outlet	L	349	349	313	316	314	331	306	308
Economizer Outlet	LC	345	346	309	313	313	326	304	306
Economizer Outlet	RC	351	351	316	321	315	332	308	309
Economizer Outlet	R	352	352	319	322	324	339	314	318
SH Pend Div Inlet Link	L	387	388	356	358	358	377	352	353
SH Pend Div Inlet Link	R	392	393	363	366	366	382	359	361
SH Desh Outlet Link	L	410	414	402	400	393	433	404	402
SH Desh Outlet Link	R	408	412	397	399	388	422	401	397
SH Pend Spcd Front In Link	L	494	494	484	485	483	510	488	484
SH Pend Spcd Front In Link	R	491	486	475	472	477	497	481	478
SH Outlet Leads	L	538	541	532	534	530	544	528	528
SH Outlet Leads	R	546	542	534	534	537	543	536	536
RH Desh Inlet Comb. Line		324	323	295	298	294	323	294	293
RH Radiant Wall Front In HDR	L	254	307	258	454	247	312	264	259
RH Radiant Wall Front In HDR	R	264	261	249	248	246	304	252	247
RH Pend Spcd Front In Links	L	299	296	295	287	288	339	299	296
RH Pend Spcd Front In Links	LC	301	298	294	287	289	337	296	291
RH Pend Spcd Front In Links	RC	310	308	291	287	286	332	291	289
RH Pend Spcd Front In Links	R	300	299	285	283	279	326	288	281
RH Outlet Leads	L	532	531	524	521	523	532	518	519
RH Outlet Leads	R	553	552	544	545	552	562	550	545
SH Spray Water		173	173	144	142	142	172	139	141
RH Spray Water		183	182	174	173	177	181	173	172
Cold RH Ext Stm to G1&G2 HTR		329	329	326	327	328	327	327	328
FW into HP HTR G1		207	206	197	197	198	206	195	195
FW into HP HTR G2		206	206	197	196	197	205	194	194
FW Out of HP HTR G1		247	246	239	238	240	246	237	238
FW Out of HP HTR G2		247	246	238	238	239	246	238	237
Stm Drain From HP HTR G1		211	211	202	202	202	212	202	201
Stm Drain From HP HTR G2		208	208	198	197	196	209	197	196
Air & Gas									
Pri Air AH Air Inlet	L	3	8	9	16	11	23	14	16
Pri Air AH Air Inlet	R	1	2	17	17	14	23	17	18
Sec Air AH Air Inlet	L	18	15	13	11	11	26	15	18
Sec Air AH Air Inlet	R	17	14	16	16	15	26	17	21
Pri Air AH Air Outlet	L	376	381	368	373	366	346	354	359
Pri Air AH Air Outlet	R	383	389	378	388	377	357	363	369
Sec Air AH Air Outlet	L	367	372	359	365	357	369	347	352
Sec Air AH Air Outlet	R	371	377	367	377	367	346	353	359
Economizer Gas Outlet	L	431	437	421	426	422	399	408	412
Economizer Gas Outlet	R	438	444	433	443	433	408	418	423
AH Gas Inlet	L	406	406	396	402	397	373	382	387
AH Gas Inlet	R	415	421	410	419	409	387	394	401
AH Gas Outlet	L	122	122	118	119	113	123	115	118
AH Gas Outlet	R	119	120	112	116	113	118	109	112

OVERFIRE AIR OPERATION STUDY

TEST DATA

TEST NO.		9	10	11	12	13	14	15	16
Date	1976	3/24	3/24	3/24	6/24	6/24	6/24	3/24	6/30
Unit Load	MW	476	473	472	524	525	523	511	526
FLOWS	kg/s								
Feedwater		380.51	372.83	366.53	426.88	421.34	424.11	401.43	415.79
PRESSURES	MPa								
Economizer Inlet		18.354	18.264	18.237	18.788	18.747	18.712	18.547	18.726
Drum		18.030	17.939	17.892	18.347	18.374	18.381	18.181	18.333
SH Outlet		16.864	16.816	16.796	16.892	16.947	16.947	16.877	16.891
Turbine 1st Stage		9.977	9.777	9.728	11.383	11.362	11.369	10.825	11.411
RH Inlet		3.282	3.227	3.234	3.661	3.661	3.627	3.558	3.661
RH Outlet		3.103	3.048	3.048	3.427	3.440	3.406	3.372	3.440
SH Spray Water		18.864	18.699	18.374	20.133	19.960	20.091	19.616	19.754
RH Spray Water		9.825	9.832	9.805	10.396	10.329	10.349	10.018	10.315
HP HTR's G1&G2 Stm In		3.220	3.165	3.172	3.716	3.716	3.709	3.496	NA
TEMPERATURES	°C								
Water & Steam									
Economizer Inlet		236	237	235	243	244	244	239	244
Economizer Outlet	L	327	326	323	340	345	341	315	342
Economizer Outlet	LC	324	324	319	342	345	342	315	346
Economizer Outlet	RC	327	328	327	346	349	343	319	346
Economizer Outlet	R	332	331	326	352	354	351	323	345
SH Pend Div Inlet Link	L	368	368	369	385	388	387	363	388
SH Pend Div Inlet Link	R	376	377	373	391	394	389	368	389
SH Desh Outlet Link	L	397	399	402	429	435	429	394	422
SH Desh Outlet Link	R	398	399	392	420	427	419	391	419
SH Pend Spcd Front In Link	L	489	488	483	507	514	507	482	510
SH Pend Spcd Front In Link	R	479	478	471	490	498	499	475	498
SH Outlet Leads	L	539	539	535	542	548	544	531	552
SH Outlet Leads	R	537	539	532	539	548	545	534	545
RH Desh Inlet Comb. Line		292	287	285	325	334	329	292	333
RH Radiant Wall Front In HDR	L	246	240	226	281	287	301	229	298
RH Radiant Wall Front In HDR	L	242	237	224	290	282	291	233	237
RH Pend Spcd Front In Links	L	283	284	272	331	322	331	273	326
RH Pend Spcd Front In Links	LC	287	284	271	327	321	326	277	329
RH Pend Spcd Front In Links	RC	282	281	278	326	324	326	283	331
RH Pend Spcd Front In Links	R	275	269	262	319	316	323	274	320
RH Outlet Leads	L	535	536	526	532	529	538	520	543
RH Outlet Leads	R	544	544	551	562	563	554	551	547
SH Spray Water		142	142	139	71	69	74	143	79
RH Spray Water		171	171	169	186	186	185	172	186
Cold RH Ext Stm to G1&G2 HTR		318	317	316	328	336	331	327	335
FW into HP HTR G1		193	193	192	57	57	59	196	39
FW into HP HTR G2		193	193	192	205	204	204	195	205
FW Out of HP HTR G1		233	234	233	95	95	95	238	85
FW Out of HP HTR G2		233	233	233	244	244	243	237	244
Stm Drain from HP HTR G1		198	197	197	98	98	97	201	43
Stm Drain from HP HTR G2		194	193	192	209	209	208	195	210
Air & Gas									
Pri Air AH Air Inlet	L	12	10	10	29	31	27	15	28
Pri Air AH Air Inlet	R	14	14	15	26	29	26	14	25
Sec Air AH Air Inlet	L	16	11	10	31	32	29	11	29
Sec Air AH Air Inlet	R	14	14	14	30	32	28	16	28
Pri Air AH Air Outlet	L	367	371	371	357	362	341	367	353
Pri Air AH Air Outlet	R	375	378	382	369	376	364	380	362
Sec Air AH Air Outlet	L	358	362	364	339	322	346	361	314
Sec Air AH Air Outlet	R	364	367	371	341	332	341	369	349
Economizer Gas Outlet	L	423	427	426	398	403	402	424	397
Economizer Gas Outlet	R	431	432	435	421	428	399	435	407
AH Gas Inlet	L	399	403	402	386	390	384	399	387
AH Gas Inlet	R	408	411	412	397	404	393	411	393
AH Gas Outlet	L	120	121	121	133	137	131	120	128
AH Gas Outlet	R	112	114	115	131	137	132	120	125

OVERFIRE AIR OPERATION STUDY

TEST DATA

TEST NO.		17	18	19	20	21	22	23	24
Date	1976	6/25	6/30	6/29	6/25	6/26	6/25	6/27	6/29
Unit Load	MW	524	526	524	521	419	422	316	322
FLOWS	kg/s								
Feedwater		410.12	418.56	418.56	412.90	341.71	322.43	262.45	244.06
PRESSURES	MPa								
Economizer Inlet		18.678	18.740	18.726	18.795	18.037	17.982	17.526	17.437
Drum		18.333	18.388	18.340	18.374	17.809	17.706	17.306	17.258
SH Outlet		16.940	16.906	16.906	16.954	16.816	16.802	16.685	16.678
Turbine 1st Stage		11.328	11.473	11.411	11.287	8.825	8.749	6.578	6.502
RH Inlet		3.627	3.661	3.661	3.627	2.792	3.565	2.055	2.075
RH Outlet		3.420	3.399	3.427	3.413	2.614	2.648	1.917	1.938
SH Spray Water		19.112	19.822	19.884	19.767	19.671	18.864	19.133	18.581
RH Spray Water		10.315	10.370	10.343	10.308	9.881	9.791	9.343	9.377
HP HTR's G1&G2 Stm In		3.716	NA	NA	NA	NA	NA	NA	NA
TEMPERATURES	°C								
Water & Steam									
Economizer Inlet		243	244	245	243	231	232	216	218
Economizer Outlet	L	346	343	343	345	326	337	306	323
Economizer Outlet	LC	345	347	343	344	327	338	306	320
Economizer Outlet	RC	347	348	343	349	329	342	303	323
Economizer Outlet	R	354	343	348	351	332	346	308	328
SH Pend Div Inlet Link	L	388	388	388	391	383	391	380	384
SH Pend Div Inlet Link	R	393	389	391	394	386	394	379	387
SH Desh Outlet Link	L	422	422	424	425	431	426	427	423
SH Desh Outlet Link	R	415	418	421	422	428	422	443	418
SH Pend Spcd Front In Link	L	502	509	506	504	508	506	509	512
SH Pend Spcd Front In Link	R	503	498	497	494	506	496	511	508
SH Outlet Leads	L	542	551	548	551	545	550	537	546
SH Outlet Leads	R	553	545	545	546	548	546	538	547
RH Desh Inlet Comb. Line		330	331	331	331	304	308	274	284
RH Radiant Wall Front In HDR	L	291	304	294	283	304	289	289	282
RH Radiant Wall Front In HDR	R	283	300	294	274	305	276	272	284
RH Pend Spcd Front In Links	L	322	329	323	314	329	329	301	312
RH Pend Spcd Front In Links	LC	322	333	324	314	328	316	296	309
RH Pend Spcd Front In Links	RC	326	334	330	319	332	313	292	313
RH Pend Spcd Front In Links	R	315	322	321	309	325	306	294	304
RH Outlet Leads	L	531	546	538	532	530	538	503	526
RH Outlet Leads	R	563	538	557	552	554	553	496	541
SH Spray Water		72	80	79	63	55	51	32	43
RH Spray Water		185	186	186	184	132	174	78	159
Cold RH Ext Stm to G1&G2 HTR		333	334	334	333	309	312	278	289
FW into HP HTR G1		43	39	46	42	43	42	64	48
FW into HP HTR G2		204	205	205	204	192	194	180	182
FW Out of HP HTR G1		94	86	86	94	94	94	88	86
FW Out of HP HTR G2		244	244	244	243	230	232	216	217
Stm Drain From HP HTR G1		92	43	51	96	47	96	44	72
Stm Drain From HP HTR G2		209	209	209	208	197	197	183	184
Air & Gas									
Pri Air AH Air Inlet	L	33	27	26	35	36	36	36	31
Pri Air AH Air Inlet	R	28	24	23	32	35	34	32	28
Sec Air AH Air Inlet	L	33	28	28	36	37	37	36	33
Sec Air AH Air Inlet	R	31	27	27	34	36	36	36	32
Pri Air AH Air Outlet	L	351	348	358	358	322	323	287	296
Pri Air AH Air Outlet	R	372	353	368	379	334	356	292	312
Sec Air AH Air Outlet	L	319	308	318	316	271	281	221	247
Sec Air AH Air Outlet	R	304	340	354	361	323	346	230	304
Economizer Gas Outlet	L	398	401	398	418	376	393	337	354
Economizer Gas Outlet	R	424	406	411	430	373	387	324	341
AH Gas Inlet	L	393	376	389	395	351	368	309	327
AH Gas Inlet	R	402	385	398	407	358	379	313	332
AH Gas Outlet	L	133	126	128	136	118	127	100	103
AH Gas Outlet	R	133	124	128	142	123	137	106	114

BASELINE OPERATION STUDY

TEST RESULTS

TEST NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
DATE 1976	3/10	3/08	3/15	3/13	5/23	5/23	5/23	3/10	3/09	3/10	5/21	5/25	3/12	3/09	3/10	3/13	5/25	5/25	5/25
UNIT LOAD MW	524	524	485	399	324	323	322	514	515	482	321	321	524	513	484	401	322	325	322
FLOWS KG/S																			
FEEDWATER (MEASURED)	412	431	381	324	262	265	262	397	406	371	237	249	403	409	371	322	246	246	244
SH SPRAY (PLANT FLOW NOZZLE)	30	11	19	9	4	4	6	30	26	23	26	16	29	18	26	7	17	20	19
MAIN STEAM (CALCULATED)	441	442	400	334	267	269	268	427	432	394	263	265	432	426	397	329	264	267	263
TURB. LEAK. (TURB. HT. BAL.)	7	7	6	5	4	4	4	6	6	6	4	4	7	6	6	5	4	4	4
HP HTR. EXT. (HEAT BAL.)	36	38	32	25	18	18	18	35	36	31	17	17	35	36	31	25	17	17	17
RH SPRAY (PLANT FLOW NOZZLE)	17	12	14	1	0	0	0	19	17	12	6	2	21	17	14	1	5	4	3
RH STEAM (CALCULATED)	416	410	375	304	244	246	246	404	407	369	248	246	411	401	374	300	247	250	245
UNIT ABSORPTION MJ/S																			
ECONOMIZER	224	212	212	170	125	135	135	219	221	215	134	153	224	225	213	164	133	148	157
FURNACE	362	401	341	327	293	286	282	349	359	325	243	244	348	360	327	328	259	243	232
DRUM - SH DESH	261	253	230	189	146	145	147	254	252	238	162	159	260	249	235	192	158	163	160
SH DESH - SH OUTLET	184	165	164	122	98	97	101	181	181	154	117	104	183	165	164	111	106	109	107
REHEATER	274	253	244	167	132	134	131	277	271	239	164	147	285	266	249	167	153	157	151
TOTAL	1304	1284	1191	975	793	797	797	1279	1284	1171	820	806	1301	1266	1189	962	809	820	807
UNIT EFFICIENCY %																			
DRY GAS LOSS	4.55	4.29	4.99	4.16	3.72	3.93	4.10	4.48	4.69	4.75	4.16	5.07	4.80	4.97	4.84	4.55	4.09	4.42	5.00
MOISTURE IN FUEL LOSS	7.55	7.21	7.42	7.03	7.13	7.57	7.15	7.48	7.41	7.49	7.24	7.28	7.55	7.29	7.49	7.57	7.19	7.16	7.23
MOISTURE IN AIR LOSS	0.11	0.10	0.12	0.10	0.09	0.09	0.10	0.10	0.11	0.11	0.10	0.12	0.11	0.12	0.11	0.11	0.10	0.10	0.12
RADIATION LOSS	0.17	0.18	0.19	0.23	0.28	0.28	0.28	0.18	0.18	0.19	0.27	0.28	0.17	0.18	0.19	0.23	0.28	0.27	0.28
ASH PIT LOSS	0.37	0.36	0.36	0.37	0.32	0.32	0.31	0.36	0.36	0.37	0.39	0.39	0.37	0.35	0.37	0.37	0.39	0.40	0.39
HEAT IN FLY ASH LOSS	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.03	0.03	0.03	0.02	0.02	0.03	0.03	0.03	0.03	0.02	0.02	0.02
PYRITE REJECTION LOSS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CARBON LOSS	0.02	0.03	0.02	0.04	0.03	0.02	0.02	0.02	0.02	0.11	0.01	0.02	0.30	0.01	0.19	0.04	0.02	0.02	0.02
ELECTROSTATIC PRECIP. LOSS	0.23	0.30	0.58	0.69	0.45	0.69	0.78	0.27	0.35	0.54	0.54	0.39	0.08	0.19	0.56	1.55	0.26	0.45	0.71
TOTAL LOSSES	13.05	12.51	13.72	12.65	12.06	12.95	12.77	12.96	13.15	13.61	12.74	13.59	13.43	13.15	13.80	14.44	12.35	12.85	13.77
EFFICIENCY	86.95	87.49	86.28	87.35	87.94	87.05	87.23	87.04	86.85	86.93	87.26	86.41	86.57	86.85	86.20	85.56	87.65	87.15	86.23
HEAT INPUT MJ/S																			
HEAT INPUT FROM FUEL	1500	1468	1380	1116	902	916	914	1469	1478	1347	940	933	1503	1458	1379	1124	923	941	936
EXCESS AIR %																			
ELECTROSTATIC PRECIP. INLET	20.7	21.8	34.7	35.6	27.7	37.5	43.2	19.4	23.7	30.6	20.4	52.5	17.1	22.6	32.2	35.7	26.1	39.5	54.8
AIR HEATER INLET	25.1	25.8	36.5	36.8	30.0	39.3	44.2	23.2	26.9	32.7	21.0	55.9	19.5	27.5	35.0	39.1	29.2	42.3	57.1
AIR HEATER OUTLET	26.7	33.3	47.0	55.8	51.6	55.8	61.9	24.9	35.9	35.7	37.6	81.5	30.2	35.4	40.1	54.0	45.3	52.7	83.2

BASELINE OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Date	1976	3/10	3/08	3/15	3/13	5/23	5/23	5/23	3/10	3/09	3/10	5/21	5/25	3/12	3/09	3/10	3/13	5/25	5/25	5/25
Unit Load	MW	524	524	485	399	324	323	322	514	515	482	321	321	524	513	484	401	322	325	322
PRODUCTS OF COMBUSTION	kg/J																			
Electrostatic Precipitator Inlet																				
Dry Products		403	409	457	449	421	472	482	398	417	434	408	510	396	413	439	480	426	469	519
Wet Products		436	442	491	481	454	507	516	432	450	467	441	545	430	446	472	515	459	503	554
Air Heater Inlet																				
Dry Air		391	415	473	491	470	509	522	386	428	425	445	576	413	420	437	511	459	499	586
Wet Air		396	421	479	497	476	516	529	391	434	431	450	584	418	425	443	518	465	506	594
Dry Products		417	422	463	452	428	478	485	410	427	440	411	522	404	429	448	492	436	479	527
Wet Products		451	455	497	485	461	513	519	444	460	474	444	556	438	461	481	527	469	512	561
Air Heater Outlet																				
Dry Air		386	391	439	430	402	455	465	380	400	416	391	493	378	394	421	461	407	451	501
Wet Air		391	396	444	436	407	461	471	385	405	421	396	500	383	400	426	467	412	457	508
Dry Products		422	446	497	513	496	532	543	416	456	450	464	604	439	454	464	542	487	527	611
Wet Products		456	479	531	546	530	568	578	449	490	484	498	640	473	487	498	578	521	561	647
GAS AND AIR FLOWS	kg/s																			
Gas Entering Precipitator		655	649	677	537	409	465	472	634	655	629	415	509	646	650	651	579	424	473	518
Gas Entering Air Heater		676	668	685	541	416	470	475	652	681	639	417	519	658	673	664	592	433	482	526
Gas Leaving Air Heater		684	704	733	610	478	521	528	660	724	652	468	597	711	710	686	650	481	528	606
Air Entering Air Heater		594	618	661	555	429	472	484	574	642	580	423	544	629	620	611	582	429	476	556
Air Leaving Air Heater		586	582	613	486	368	422	430	566	598	568	372	466	576	583	588	525	381	430	475
Air Heater Leakage		8	36	48	68	62	51	53	8	43	13	51	78	53	38	23	57	48	46	80
AIR HEATER PERFORMANCE																				
Air Heater Leakage	%	1.1	5.4	7.0	12.6	14.9	10.8	11.2	1.2	6.4	2.0	12.3	15.1	8.0	5.6	3.4	9.7	11.2	9.5	15.2
Gas Side Efficiency	%	72.1	72.7	71.9	72.6	70.6	72.4	72.0	72.1	71.8	72.2	67.8	70.1	70.4	71.1	72.0	72.6	69.8	71.1	70.9
Gas Drop	C	264	250	256	221	187	195	196	264	258	261	191	205	261	266	258	224	196	206	209
Air Rise	C	254	238	244	209	185	184	187	256	250	253	199	201	262	261	251	214	196	200	201
Temperature Head	C	373	351	363	312	272	276	279	373	367	368	291	301	378	381	366	316	288	297	302
FUEL ANALYSIS																				
Carbon	%	48.6	50.3	49.8	49.4	48.9	49.7	51.3	49.0	50.0	48.8	51.1	50.6	49.2	50.6	48.8	49.9	50.5	50.6	50.6
Hydrogen	%	3.4	3.4	3.4	3.3	3.3	3.7	3.6	3.4	3.5	3.4	3.6	3.6	3.4	3.4	3.4	3.4	3.4	3.4	3.5
Nitrogen	%	.6	.6	.7	.7	.7	.7	.8	.8	.4	.7	.8	.9	.7	.9	.7	.7	.8	.8	.8
Oxygen	%	11.6	12.3	12.3	12.2	12.6	11.7	11.9	12.7	11.8	12.2	11.9	11.7	12.3	12.7	12.2	12.5	12.3	11.9	12.0
Sulfur	%	1.0	.8	.7	.8	.8	.9	.6	.7	1.0	.8	.7	.7	.8	.7	.8	.7	.6	.6	.6
Moisture	%	25.1	24.4	24.4	24.4	25.5	25.1	24.7	24.7	24.5	24.9	24.5	25.0	24.6	24.2	24.9	24.2	25.2	25.1	25.1
Ash	%	9.7	8.2	8.7	9.2	8.2	8.2	7.1	8.7	8.8	9.2	7.4	7.5	9.0	7.5	9.2	8.6	7.2	7.6	7.4
HHV	kJ/kg	19724	20108	19648	19934	19841	19724	20492	19748	20097	19736	20422	20353	19562	20120	19736	18841	20050	20097	20166

BIASED FIRING OPERATION STUDY

TEST RESULTS

TEST NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Date 1976	5/19	5/19	3/14	5/19	5/12	5/12	5/16	5/21	6/27	5/23	5/19	5/10	3/16	5/12	3/13	5/16	5/21	5/23
Unit Load MW	505	506	525	506	422	422	421	320	314	324	491	497	523	423	400	422	320	323
FLOWS kg/s																		
Feedwater (Measured)	406	412	404	404	349	345	342	237	256	260	391	384	407	349	321	345	234	254
SH Spray (Plant Flow Nozzle)	21	17	29	26	4	7	3	27	3	7	26	33	31	5	4	5	27	11
Main Steam (Calculated)	426	428	433	431	352	352	344	263	258	268	417	417	438	353	325	350	261	264
Turb. Leak. (Turb. Heat Bal.)	6	6	7	7	5	5	5	4	4	4	6	6	7	5	5	5	4	4
HP Htr. Ext. (Heat Balance)	35	35	35	34	28	27	27	16	18	18	32	30	35	27	25	26	16	18
RH Spray (Plant Flow Nozzle)	13	16	21	12	2	1	1	4	0	0	13	18	18	2	1	1	3	0
RH Steam (Calculated)	398	404	412	402	321	321	314	247	236	245	392	399	415	323	296	320	244	242
UNIT ABSORPTION MJ/s																		
Economizer	222	224	228	222	178	168	174	132	119	127	227	227	223	190	161	190	142	130
Furnace	356	363	347	354	345	351	340	245	292	287	335	319	366	333	329	328	232	273
Drum - SH DESH	244	242	264	245	187	193	196	160	142	148	242	250	249	195	183	201	157	147
SH DESH - SH Outlet	182	180	181	192	134	133	117	120	90	102	185	190	191	131	112	122	122	104
Reheater	248	263	284	248	176	177	173	160	120	135	250	269	279	179	163	178	152	134
Total	1252	1272	1304	1262	1021	1022	1001	817	763	799	1239	1256	1308	1027	949	1020	805	788
UNIT EFFICIENCY %																		
Dry Gas Loss	5.33	5.31	5.31	5.20	4.63	4.25	4.54	4.38	3.84	4.16	5.45	5.22	4.86	4.73	4.76	5.23	5.03	3.89
Moisture in Fuel Loss	7.24	7.29	7.55	7.25	7.26	7.82	7.72	7.23	7.11	7.17	7.30	7.36	7.63	7.01	7.29	7.13	7.16	7.53
Moisture in Air Loss	0.13	0.12	0.12	0.12	0.11	0.10	0.11	0.10	0.09	0.10	0.13	0.12	0.11	0.11	0.11	0.12	0.12	0.09
Radiation Loss	0.18	0.18	0.17	0.18	0.22	0.22	0.23	0.27	0.29	0.28	0.17	0.18	0.17	0.22	0.24	0.22	0.28	0.25
Ash Pit Loss	0.37	0.35	0.36	0.34	0.37	0.37	0.36	0.39	0.35	0.33	0.35	0.35	0.36	0.38	0.36	0.35	0.40	0.33
Heat in Fly Ash Loss	0.03	0.03	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.02	0.03	0.02	0.03	0.02
Pyrite Rejection Loss	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Carbon Loss	0.02	0.03	0.35	0.02	0.03	0.02	0.02	0.01	0.02	0.04	0.02	0.03	0.03	0.02	0.02	0.02	0.02	0.04
Electrostatic Precip. Loss	0.50	0.15	0.53	0.34	0.60	0.48	0.70	0.42	0.30	0.52	0.82	0.21	0.10	0.57	0.81	0.78	0.32	1.14
Total Losses	13.81	13.46	14.44	13.48	13.24	13.29	13.70	12.83	12.03	12.63	14.27	13.51	13.31	13.08	13.63	13.89	13.38	13.33
Efficiency	86.19	86.54	85.56	86.52	86.76	86.71	86.30	87.17	87.97	87.37	85.73	86.49	86.69	86.92	86.37	86.11	86.62	86.67
HEAT INPUT MJ/s																		
Heat Input from Fuel	1453	1470	1524	1459	1177	1179	1160	937	867	915	1445	1452	1509	1182	1099	1185	929	909
EXCESS AIR %																		
Electrostatic Precip. Inlet	20.4	19.4	15.2	19.0	26.1	21.7	30.7	19.7	34.2	29.2	23.1	24.6	18.4	34.1	35.8	41.3	35.9	36.6
Air Heater Inlet	23.2	23.2	18.4	23.2	28.4	24.5	32.3	21.1	35.9	32.4	23.9	29.2	25.4	36.7	36.7	43.2	37.6	38.4
Air Heater Outlet	42.3	41.3	28.4	40.4	47.1	38.4	45.1	39.5	56.1	48.2	46.2	41.3	36.8	50.4	54.8	65.8	56.0	58.2

BIASED FIRING OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
DATE	1976	5/12	5/19	3/14	5/19	5/12	5/12	5/16	5/21	6/27	5/23	5/19	5/10	3/16	5/12	3/13	5/16	5/21	5/23
UNIT LOAD	MW	505	506	525	506	422	422	421	320	314	324	491	497	523	423	400	422	320	323
PRODUCTS OF COMBUSTION	MG/J																		
ELECTROSTATIC PRECIPITATOR INLET																			
DRY PRODUCTS		405	404	393	398	437	420	451	400	429	440	421	422	402	451	455	471	450	461
WET PRODUCTS		437	436	425	431	471	455	485	433	462	473	454	455	435	484	489	504	483	496
AIR HEATER INLET																			
DRY AIR		448	444	407	435	482	449	475	441	473	474	476	442	420	477	496	526	490	508
WET AIR		453	450	412	440	489	455	481	446	479	480	482	448	425	483	503	533	497	515
DRY PRODUCTS		414	419	403	411	445	429	455	404	435	451	423	436	424	460	458	477	455	467
WET PRODUCTS		446	452	436	444	478	465	491	437	468	484	456	470	458	492	492	510	488	502
AIR HEATER OUTLET																			
DRY AIR		386	385	374	380	420	403	431	382	411	422	403	403	383	433	438	453	432	444
WET AIR		391	390	379	385	425	409	439	387	416	428	408	408	388	439	443	459	438	450
DRY PRODUCTS		475	478	436	466	508	475	497	463	497	502	496	476	461	504	516	550	514	534
WET PRODUCTS		509	512	469	500	542	511	533	497	531	536	530	509	495	537	551	584	548	567
GAS AND AIR FLOWS	KG/S																		
GAS ENTERING PRECIPITATOR		635	641	648	629	554	536	563	406	401	433	656	661	656	572	537	597	449	451
GAS ENTERING AIR HEATER		648	664	664	648	563	548	570	409	406	443	659	682	691	582	541	604	453	456
GAS LEAVING AIR HEATER		740	753	715	730	638	602	618	466	460	490	766	739	747	635	606	692	509	515
AIR ENTERING AIR HEATER		658	662	628	642	576	536	558	418	415	439	697	650	641	571	553	632	462	468
AIR LEAVING AIR HEATER		568	573	578	562	500	482	509	363	361	392	590	592	585	519	487	544	407	409
AIR HEATER LEAKAGE		92	89	51	82	75	54	48	57	54	47	107	57	56	53	65	88	56	59
AIR HEATER PERFORMANCE																			
AIR HEATER LEAKAGE	%	13.3	13.2	7.6	12.5	13.2	10.0	8.7	13.6	13.4	10.8	16.2	8.5	8.1	9.1	12.0	14.4	12.1	13.0
GAS SIDE EFFICIENCY	%	66.0	66.3	67.6	66.4	69.9	70.6	70.6	65.9	69.4	68.6	66.2	69.4	71.0	70.9	69.4	68.9	66.2	71.0
GAS DROP	C	227	226	254	226	219	216	218	187	178	180	227	249	259	230	214	220	195	183
AIR RISE	C	319	314	347	315	287	282	284	271	239	247	317	329	333	296	284	292	279	236
TEMPERATURE HEAD	C	352	349	384	350	321	313	317	293	265	271	353	367	372	331	317	328	303	265
FUEL ANALYSIS																			
CARBON	%	50.4	51.0	49.8	50.2	52.4	50.3	50.1	50.4	48.5	50.1	51.5	50.5	48.8	51.2	50.2	51.0	49.7	48.9
HYDROGEN	%	3.4	3.4	3.4	3.4	3.7	3.8	3.7	3.4	3.3	3.5	3.6	3.4	3.3	3.5	3.5	3.5	3.4	3.6
NITROGEN	%	.7	.7	.7	.8	.8	.7	.7	.7	.6	.7	.7	.7	.7	.7	.8	.7	.8	.6
OXYGEN	%	12.5	12.2	12.3	12.5	11.6	11.7	11.8	12.5	13.6	11.6	11.0	12.2	12.2	12.1	11.8	12.1	11.8	11.5
SULFUR	%	.5	.6	.7	.7	.6	.6	.5	.6	.5	1.0	.8	.6	.7	.9	.7	.6	.8	1.0
MOISTURE	%	24.7	25.0	24.4	24.7	23.9	25.9	25.3	25.4	25.9	23.9	24.2	25.1	25.6	23.5	24.7	24.4	24.6	25.8
ASH	%	7.7	7.1	8.7	7.7	7.0	7.0	7.9	7.0	7.6	9.2	7.5	7.5	8.7	8.1	8.3	7.7	8.9	8.6
HHV	KJ/KG	20097	20097	19648	20166	20432	19957	19771	20236	20273	19911	20399	20027	19329	20469	20166	20492	20166	19724

OVERFIRE AIR OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12
Date	1976	3/17	3/17	3/20	3/20	3/22	3/20	3/20	3/20	3/24	3/24	3/24	6/24
Unit Load	MW	517	512	524	525	526	521	522	522	476	473	472	524
FLOWS	kg/s												
Feedwater (Measured)		399	400	432	432	420	444	438	435	381	373	367	427
SH Spray (Plant Flow Nozzle)		26	26	7	12	24	2	3	4	17	17	22	19
Main Steam (Calculated)		425	426	439	445	444	446	441	439	398	390	389	446
Turbine Leakage (Turbine Heat Balance)		6	6	7	7	7	7	7	7	6	6	6	6
HP Htr. Extraction (Heat Balance)		34	34	38	37	36	38	39	38	31	31	30	35
RH Spray (Plant Flow Nozzle)		20	20	14	15	15	3	12	13	13	14	16	11
RH Steam (Calculated)		404	405	409	416	416	404	407	407	374	367	368	415
UNIT ABSORPTION	MJ/s												
Economizer		227	230	160	167	159	200	151	151	178	174	165	237
Furnace		341	340	467	459	449	432	485	479	387	380	383	376
Drum - SH DESH		246	247	246	255	257	236	245	241	225	223	225	258
SH DESH - SH Outlet		185	183	156	163	180	175	150	153	159	155	154	187
Reheater		281	285	287	294	298	227	278	284	272	264	264	261
Total		1280	1286	1315	1338	1342	1269	1310	1309	1221	1196	1191	1319
UNIT EFFICIENCY	%												
Dry Gas Loss		4.69	4.86	4.54	4.55	4.36	4.05	4.20	4.08	5.09	5.23	5.02	4.61
Moisture in Fuel Loss		7.94	7.61	7.46	7.36	7.28	7.39	7.34	7.32	7.37	7.29	7.34	7.07
Moisture in Air Loss		0.11	0.11	0.11	0.11	0.10	0.09	0.10	0.10	0.12	0.12	0.12	0.11
Radiation Loss		0.18	0.18	0.17	0.17	0.17	0.18	0.17	0.17	0.19	0.19	0.19	0.17
Ash Pit Loss		0.36	0.36	0.36	0.36	0.36	0.35	0.36	0.36	0.35	0.36	0.33	0.35
Heat in Fly Ash Loss		0.03	0.03	0.03	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.02	0.02
Pyrite Rejection Loss		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Carbon Loss		0.01	0.02	0.02	0.01	0.02	0.03	0.04	0.03	0.01	0.02	0.01	0.02
Electrostatic Precipitator Loss		0.79	0.07	0.80	0.50	0.51	0.25	0.32	0.33	0.96	0.80	0.90	0.44
Total Losses		14.12	13.25	13.50	13.20	12.84	12.37	12.57	12.43	14.13	14.05	13.94	12.80
Efficiency		85.88	86.75	86.50	86.80	87.16	87.63	87.43	87.57	85.87	85.95	86.06	87.20
HEAT INPUT	MJ/s												
Heat Input from Fuel		1490	1482	1520	1541	1540	1448	1498	1495	1422	1392	1384	1513
EXCESS AIR	%												
Electrostatic Precipitator Inlet		23.9	23.2	21.8	19.7	20.4	13.3	13.9	15.1	36.8	35.8	30.0	23.9
Air Heater Inlet		25.4	30.8	23.2	22.5	23.9	18.4	19.0	19.7	37.7	37.6	30.8	26.1
Air Heater Outlet		33.3	34.2	33.3	31.6	30.8	26.9	30.8	26.9	49.4	49.3	40.4	35.8

OVERFIRE AIR OPERATION STUDY

TEST RESULTS

TEST NO.		13	14	15	16	17	18	19	20	21	22	23	24
Date	1976	6/24	6/24	3/25	6/30	6/25	6/30	6/29	6/25	6/26	6/25	6/27	5/29
Unit Load	MW	525	523	511	526	524	526	524	521	419	422	316	322
FLOWS	kg/s												
Feedwater (Measured)		421	424	401	416	410	419	419	413	342	322	262	244
SH Spray (Plant Flow Nozzle)		22	19	23	23	30	23	22	25	9	20	1	15
Main Steam (Calculated)		444	443	425	438	440	441	441	438	350	342	263	259
Turbine Leakage (Turbine Heat Balance)		7	7	6	7	7	7	7	7	5	5	4	4
HP Htr. Extraction (Heat Balance)		35	35	34	34	34	35	35	34	27	25	19	17
RH Spray (Plant Flow Nozzle)		16	8	18	12	14	10	12	17	0	5	0	0
RH Steam (Calculated)		418	408	402	409	413	409	412	414	318	316	240	238
UNIT ABSORPTION	MJ/s												
Economizer		243	233	159	227	237	233	228	240	173	186	115	129
Furnace		360	375	428	368	353	366	371	354	346	302	306	261
Drum - SH DESH		265	253	245	253	260	254	256	261	194	202	144	148
SH DESH - SH Outlet		195	196	171	203	213	204	199	202	141	152	82	114
Reheater		263	243	284	243	257	233	249	263	173	202	123	133
Total		1326	1300	1286	1295	1320	1289	1302	1320	1027	1044	770	785
UNIT EFFICIENCY	%												
Dry Gas Loss		4.80	4.62	4.74	4.42	4.66	4.26	4.21	4.75	4.22	4.43	3.25	3.73
Moisture in Fuel Loss		7.05	7.03	7.38	7.12	7.48	7.18	7.12	7.27	6.92	6.97	6.91	6.94
Moisture in Air Loss		0.11	0.11	0.11	0.10	0.11	0.10	0.10	0.11	0.10	0.10	0.08	0.09
Radiation Loss		0.17	0.17	0.18	0.18	0.17	0.18	0.17	0.17	0.22	0.22	0.29	0.28
Ash Pit Loss		0.35	0.35	0.37	0.35	0.36	0.35	0.34	0.35	0.37	0.34	0.35	0.36
Heat in Fly Ash Loss		0.03	0.02	0.03	0.02	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Pyrite Rejection Loss		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Carbon Loss		0.02	0.02	0.01	0.06	0.05	0.05	0.03	0.03	0.02	0.02	0.03	0.02
Electrostatic Precipitator Loss		0.56	0.39	0.74	0.29	0.25	0.72	0.34	0.66	0.59	0.50	0.59	0.77
Total Losses		13.10	12.72	13.57	12.55	13.12	12.87	12.34	13.37	12.47	12.61	11.53	12.22
Efficiency		86.90	87.28	86.43	87.45	86.88	87.13	87.66	86.63	87.53	87.39	88.47	87.78
HEAT INPUT	MJ/s												
Heat Input from Fuel		1526	1489	1488	1481	1519	1479	1485	1524	1173	1195	870	894
EXCESS AIR	%												
Electrostatic Precipitator Inlet		26.9	26.9	18.3	24.6	26.2	23.2	19.1	25.4	30.0	28.5	32.5	34.2
Air Heater Inlet		28.5	27.7	20.4	26.1	28.5	24.7	19.8	27.7	32.4	30.1	35.1	34.2
Air Heater Outlet		41.4	38.6	30.8	36.8	40.5	37.7	30.9	39.5	48.3	42.4	51.6	50.5

OVERFIRE AIR OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12
Date	1976	3/17	3/17	3/20	3/20	3/22	3/20	3/20	3/20	3/24	3/24	3/24	6/24
Unit Load	MW	517	512	524	525	526	521	522	522	476	473	472	524
PRODUCTS OF COMBUSTION	MG/J												
Electrostatic Precipitator Inlet													
Dry Products		413	414	412	400	401	383	384	387	461	453	443	412
Wet Products		448	447	446	433	434	416	416	419	494	486	476	444
Air Heater Inlet													
Dry Air		420	406	427	412	406	393	403	392	480	473	455	425
Wet Air		425	411	433	417	411	398	409	397	486	479	461	430
Dry Products		417	438	417	409	412	399	400	401	463	459	445	419
Wet Products		452	472	450	442	445	432	433	434	497	492	478	451
Air Heater Outlet													
Dry Air		394	395	394	382	384	365	366	369	442	436	424	394
Wet Air		400	400	400	387	389	370	370	374	448	441	429	399
Dry Products		443	449	450	438	434	427	438	424	501	496	476	450
Wet Products		478	483	483	471	467	460	471	457	535	530	510	482
GAS AND AIR FLOWS	KG/S												
Gas Entering Precipitator		668	662	678	667	668	602	623	626	702	676	659	672
Gas Entering Air Heater		673	700	684	681	685	626	649	649	707	685	662	682
Gas Leaving Air Heater		712	716	734	726	719	666	706	683	761	738	706	729
Air Entering Air Heater		633	609	658	642	633	576	613	594	691	667	638	650
Air Leaving Air Heater		596	593	608	596	599	536	554	559	637	614	594	604
Air Heater Leakage		39	16	50	45	34	40	57	34	54	53	44	47
AIR HEATER PERFORMANCE													
Air Heater Leakage	%	5.6	2.3	7.4	6.7	5.0	6.4	8.8	5.4	7.7	7.7	6.6	7.0
Gas Side Efficiency	%	71.9	72.4	72.3	72.2	73.1	71.7	72.1	73.1	72.0	71.4	71.7	70.0
Gas Drop	C	267	272	264	268	268	237	250	256	262	264	265	235
Air Rise	C	339	346	333	341	333	313	318	321	331	337	339	297
Temperature Head	C	379	382	372	378	373	337	354	357	371	377	377	344
FUEL ANALYSIS													
Carbon	%	47.30	48.80	50.30	49.80	50.00	50.20	49.80	49.70	50.40	50.20	52.30	51.50
Hydrogen	%	3.20	3.30	3.50	4.40	3.50	3.50	3.40	3.40	3.50	3.50	3.60	3.60
Nitrogen	%	0.70	0.70	0.80	0.80	0.80	0.80	0.70	0.60	0.80	0.80	0.80	0.80
Oxygen	%	11.80	12.10	12.00	11.80	11.80	12.00	12.00	12.00	13.10	11.90	13.60	12.70
Sulfur	%	0.70	0.60	0.60	0.70	0.70	0.60	0.80	0.90	0.70	0.90	0.50	0.50
Moisture	%	27.90	25.80	24.80	24.90	24.10	25.20	24.90	24.90	24.00	23.90	24.00	23.80
Ash	%	8.40	8.70	8.00	8.60	9.10	7.70	8.40	8.50	7.50	8.80	5.20	7.10
HHV	KJ/KG	19050	19492	20050	20097	20306	20120	19980	20004	20004	20283	20515	20864

OVERFIRE AIR OPERATION STUDY

TEST RESULTS

TEST NO.		13	14	15	16	17	18	19	20	21	22	23	24
Date	1976	6/24	6/24	3/25	6/30	6/25	6/30	6/29	6/25	6/26	6/25	6/27	5/29
Unit Load	MW	525	523	511	526	524	526	524	521	419	422	316	322
PRODUCTS OF COMBUSTION	μG/J												
Electrostatic Precipitator Inlet													
Dry Products		409	412	404	411	413	391	380	409	440	417	421	433
Wet Products		441	444	437	443	442	423	412	442	472	449	454	466
Air Heater Inlet													
Dry Air		431	428	421	426	432	412	396	428	473	436	454	465
Wet Air		436	433	426	432	437	418	401	434	479	442	459	471
Dry Products		414	415	411	415	420	395	382	416	448	422	429	433
Wet Products		446	446	444	448	454	428	414	449	480	454	462	466
Air Heater Outlet													
Dry Air		391	394	387	393	394	373	362	391	422	398	403	415
Wet Air		396	399	392	398	400	378	366	396	427	403	408	420
Dry Products		454	448	445	449	458	435	416	453	499	460	479	484
Wet Products		486	481	478	482	492	468	448	487	532	492	513	517
GAS AND AIR FLOWS	kg/s												
Gas Entering Precipitator		673	661	650	656	671	626	612	674	554	536	395	417
Gas Entering Air Heater		680	664	661	663	690	633	615	684	563	542	402	417
Gas Leaving Air Heater		742	716	711	714	747	692	665	742	624	588	446	462
Air Entering Air Heater		665	645	634	640	664	618	595	661	562	528	399	421
Air Leaving Air Heater		604	594	583	589	608	559	544	604	501	482	355	375
Air Heater Leakage		62	52	50	51	57	59	50	58	61	46	44	45
AIR HEATER PERFORMANCE													
Air Heater Leakage	%	9.0	7.7	7.8	7.6	8.4	9.3	8.3	8.3	10.8	8.5	11.1	11.0
Gas Side Efficiency	%	68.8	69.5	70.9	71.0	70.1	70.0	70.4	69.4	70.9	69.3	73.0	71.5
Gas Drop	C	234	233	260	239	239	230	240	237	208	216	183	195
Air Rise	C	286	299	336	291	272	284	297	292	249	266	207	232
Temperature Head	C	348	343	374	344	348	336	349	349	301	319	258	280
FUEL ANALYSIS													
Carbon	%	49.90	50.10	50.20	50.80	47.80	48.90	49.40	49.40	51.90	50.40	49.30	49.20
Hydrogen	%	3.40	3.40	3.50	3.50	3.30	3.40	3.40	3.40	3.60	3.50	3.40	3.40
Nitrogen	%	0.60	0.60	0.70	0.80	0.70	0.80	0.70	0.60	0.60	0.70	0.60	0.70
Oxygen	%	13.80	13.80	11.90	12.70	13.70	14.10	14.40	13.80	12.90	14.60	14.30	13.60
Sulfur	%	0.40	0.50	0.90	0.50	0.50	0.50	0.40	0.40	0.60	0.70	0.40	0.70
Moisture	%	24.60	24.20	23.50	24.70	25.70	25.60	25.10	25.30	22.90	23.90	25.10	24.10
Ash	%	7.30	7.40	9.30	7.10	8.60	6.70	6.60	7.10	7.50	6.20	6.90	8.30
HHV	kJ/kg	20562	20492	19911	20678	19399	20515	20562	20120	20585	20655	20515	20283

BASELINE OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
T/C # 1	0.0	45.55	23.36	50.03	32.32	23.26	32.03	2.90	120.87	0.0	2.81	23.25	2.28	29.37	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	106.11	0.0	0.0	0.0	0.0	0.0	0.0	52.43	0.0	0.0	0.0	0.0	0.0	0.0
4	18.73	191.56	8.33	128.47	55.78	59.41	73.78	22.42	166.53	28.88	28.03	195.36	29.76	79.38	31.64
5	3.10	80.34	55.98	52.73	29.62	31.33	27.53	13.87	8.40	102.61	12.05	17.02	40.62	0.0	32.84
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	15.17	110.47	4.93	82.82	3.39	3.58	0.0	150.68	140.97	83.43	0.0	73.05	18.99	35.70	127.62
8	18.02	19.37	24.47	3.50	73.31	85.24	94.16	28.01	62.63	31.81	70.96	61.54	51.71	50.41	31.26
9	16.24	3.73	32.58	54.83	65.29	80.68	75.01	33.06	8.59	31.81	47.32	51.54	40.81	7.36	33.67
10	110.75	120.53	72.57	125.19	75.31	80.68	82.30	107.40	100.05	101.91	60.95	63.36	54.43	94.18	93.13
11	91.57	45.36	57.10	74.88	63.47	70.65	57.71	97.90	90.91	96.43	76.43	66.09	53.53	67.71	102.87
12	22.49	78.16	63.45	53.04	56.19	55.19	53.16	41.76	69.01	43.57	62.77	50.63	96.39	55.87	43.33
13	56.00	51.18	55.26	56.67	50.74	56.09	45.90	60.67	58.08	59.03	44.60	48.82	73.57	56.77	65.15
14	95.22	80.35	103.35	58.47	0.0	0.0	0.0	83.29	53.53	109.21	0.0	0.0	47.16	44.05	90.70
15	15.29	47.65	29.82	115.05	87.20	86.20	97.86	106.24	33.49	5.23	38.33	20.07	70.76	88.62	18.43
16	8.28	82.39	76.15	109.57	34.49	33.50	27.90	16.14	96.32	20.09	71.93	58.87	18.22	90.45	17.48
17	61.39	50.74	51.57	161.63	157.51	154.67	161.77	66.80	41.64	63.54	108.42	92.58	88.10	110.54	62.08
18	44.10	92.32	111.77	77.63	126.46	119.06	116.12	58.06	85.36	61.71	92.90	106.27	48.91	79.49	57.22
19	73.24	93.78	103.38	50.32	110.94	101.71	103.33	64.62	89.02	72.65	0.0	97.14	54.37	84.06	74.23
20	50.46	74.06	69.78	82.19	109.11	97.15	93.29	56.60	48.91	60.81	53.73	56.14	68.94	53.06	63.29
21	5.71	56.55	47.95	24.13	64.42	56.14	59.57	11.90	8.53	14.76	83.78	64.32	23.58	12.52	15.12
22	131.73	113.74	143.80	102.36	0.0	0.0	0.0	132.05	124.69	130.24	0.0	0.0	153.91	123.38	136.09
23	118.94	121.78	37.11	144.37	161.28	155.71	162.80	58.29	146.61	45.41	103.06	77.20	38.07	97.81	36.42
24	76.03	79.40	174.84	62.23	257.88	261.42	263.95	94.05	100.03	94.62	137.76	200.41	134.74	97.81	95.90
25	60.53	108.62	83.53	47.69	141.19	135.62	138.15	72.15	106.42	75.45	74.78	112.79	71.73	101.46	76.43
26	53.24	26.33	107.27	0.0	164.93	152.97	155.50	89.67	116.47	0.0	100.33	122.83	78.72	0.0	74.61
27	40.53	70.54	132.70	33.21	159.45	126.48	140.89	80.91	75.07	83.67	103.97	100.31	100.94	64.96	47.29
28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	97.72	33.34	36.92	98.53	122.76	114.45	106.94	77.96	100.73	75.26	59.15	80.68	41.79	32.05	69.85
30	36.69	51.07	47.80	165.19	150.16	147.32	138.90	52.45	64.23	58.85	84.65	108.06	86.12	65.66	48.01
31	91.33	93.93	102.50	70.25	192.14	200.25	198.22	118.14	97.99	128.21	109.29	131.80	103.47	91.28	119.75
32	65.78	126.36	85.98	69.34	150.16	155.54	123.37	94.03	50.57	83.47	91.04	137.28	119.00	51.09	85.66
33	64.87	111.52	102.50	52.96	140.11	146.41	137.07	93.30	73.34	84.38	91.95	106.23	89.77	70.22	82.01
34	64.87	116.53	94.28	51.15	130.07	127.23	116.98	74.31	62.40	68.87	57.33	100.75	72.43	62.92	71.06
35	28.56	86.07	73.76	19.54	101.76	98.01	95.07	40.10	30.63	36.16	128.47	83.42	56.94	26.64	37.13
36	44.26	76.93	54.51	206.61	185.24	166.89	159.39	78.47	44.53	58.28	102.40	66.51	71.84	52.32	55.32
37	87.09	26.24	82.75	157.35	158.77	145.89	130.17	107.69	58.17	89.28	86.89	90.21	86.44	57.78	84.48
38	89.82	148.54	135.48	50.06	198.00	185.14	156.65	80.50	68.19	84.72	108.79	79.27	115.67	60.51	85.70
39	44.26	29.44	55.40	40.04	137.77	128.55	124.69	74.09	81.88	46.46	74.12	103.90	91.00	61.42	71.11
40	71.57	91.55	73.05	51.52	140.90	145.89	132.91	109.15	85.53	106.63	72.30	99.34	100.14	84.22	93.00
41	84.35	113.47	57.06	67.71	144.16	141.33	135.64	89.42	99.22	85.63	85.06	108.47	83.70	98.83	91.78
42	71.57	100.32	111.05	52.43	0.0	0.0	0.0	135.91	70.93	116.68	0.0	0.0	102.88	71.45	107.61
43	158.04	130.39	51.17	152.25	179.25	156.34	147.92	119.15	81.29	107.89	92.77	100.66	66.69	54.46	78.44
44	69.23	135.34	77.01	172.33	142.02	172.77	164.35	76.79	122.38	75.93	100.07	111.61	71.25	121.99	68.71
45	93.80	105.73	103.17	147.51	200.23	178.25	169.83	99.43	115.99	89.62	126.55	106.14	156.17	125.64	94.26

BASELINE OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m²

TEST		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
T/C #	46	68.24	45.21	52.17	31.93	47.30	38.77	25.97	67.31	72.16	76.24	60.88	83.32	79.46	74.51	0.0
	47	76.45	89.12	77.51	59.17	131.78	134.43	123.26	81.90	80.37	65.91	83.65	93.36	99.55	79.98	78.44
	48	87.40	101.55	97.09	65.72	139.08	137.17	128.74	92.85	96.81	93.27	69.98	98.83	107.77	94.59	83.31
	49	66.12	119.32	133.31	42.52	37.05	48.42	43.99	81.90	100.16	67.73	54.52	88.80	93.15	91.84	82.09
	50	146.44	108.77	141.22	13.91	153.03	146.81	134.91	143.31	135.76	115.80	134.56	122.35	98.31	142.67	77.54
	51	119.96	126.43	92.61	116.38	49.50	90.38	117.56	112.63	56.36	96.63	84.35	96.79	76.40	81.48	93.36
	52	113.56	137.57	105.51	23.07	165.53	149.73	147.70	119.20	131.19	101.19	109.90	92.23	124.80	104.31	103.10
	53	54.26	79.07	65.45	53.45	93.20	84.91	87.44	62.25	65.46	54.69	57.04	46.72	107.44	69.62	50.83
	54	90.73	27.35	53.16	38.99	45.88	83.08	118.47	87.79	24.66	73.81	61.58	83.11	83.70	96.09	73.89
	55	103.52	43.24	97.33	23.14	119.55	104.98	100.21	108.97	19.30	101.19	128.16	92.23	129.36	100.65	97.01
	56	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	57	0.0	0.0	0.0	0.0	36.84	50.33	48.31	0.0	0.0	0.0	151.87	121.42	0.0	0.0	0.0
	58	135.23	138.99	150.02	70.05	39.55	47.60	47.40	165.29	137.31	161.97	116.26	128.73	169.26	127.79	179.96
	59	86.82	84.92	84.23	33.72	30.52	35.84	32.03	92.23	72.47	87.99	104.38	83.08	93.47	112.26	97.17
	60	31.49	46.07	33.48	3.23	78.96	81.59	81.39	38.13	17.39	46.30	60.95	41.57	53.53	20.58	50.59
	61	27.88	9.40	35.20	0.0	57.10	58.82	55.89	77.45	14.73	66.31	56.40	49.73	29.95	47.68	59.08
	62	190.17	31.59	55.90	17.87	108.16	98.02	92.34	138.09	69.01	128.39	95.59	77.03	71.75	79.57	133.32
	63	44.17	101.53	131.92	66.08	90.81	76.12	63.17	57.03	115.57	53.57	61.86	52.45	64.45	79.57	60.29
	64	77.87	140.23	117.51	36.71	7.84	8.61	7.57	82.56	101.87	77.26	76.43	135.45	48.98	103.31	82.18
	65	70.50	98.89	25.32	131.49	94.50	86.20	86.90	21.13	37.11	88.16	41.04	35.30	50.73	48.52	34.23
	66	25.11	92.32	37.05	102.27	107.29	99.88	89.64	34.09	38.92	31.77	85.60	58.87	38.02	42.16	31.82
	67	41.38	142.01	75.25	115.05	128.29	118.15	105.16	47.14	59.83	49.89	72.84	65.23	73.50	52.15	54.79
	68	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	69	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	70	150.91	163.41	172.10	102.36	0.0	0.0	0.0	133.51	92.72	132.07	0.0	0.0	160.30	150.78	161.65
	71	97.93	110.08	59.82	99.53	135.71	123.74	113.49	65.58	50.78	51.77	82.08	44.47	58.06	66.78	54.56
	72	96.11	123.24	156.62	138.89	184.09	179.44	169.19	107.20	129.26	105.58	228.98	62.62	113.73	115.16	100.77
	73	86.06	142.96	151.02	123.37	171.31	159.36	145.46	99.17	127.43	98.27	104.89	107.31	134.74	93.24	97.12
	74	28.77	58.98	29.89	106.76	118.36	110.05	98.88	32.88	32.64	31.83	151.46	56.26	100.94	38.59	29.19
	75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	76	60.32	36.42	61.50	31.23	140.11	135.45	130.68	69.21	86.12	66.14	91.95	140.02	78.82	108.56	69.85
	77	0.0	0.0	0.0	0.0	152.89	149.15	142.55	0.0	0.0	0.0	186.90	60.65	0.0	0.0	0.0
	78	71.25	64.73	110.72	37.55	125.50	117.19	107.85	83.07	87.03	79.82	85.57	96.19	85.21	60.19	156.28
	79	35.79	132.71	91.54	97.62	94.45	116.27	106.02	45.18	51.48	42.50	66.43	109.88	67.87	51.09	41.96
	80	56.08	68.32	110.14	51.52	207.12	197.00	173.08	73.36	39.09	80.16	111.53	89.30	80.05	45.96	74.75
	81	120.86	169.72	33.63	69.71	228.99	229.81	166.69	120.11	126.63	114.85	111.53	130.38	113.84	140.85	122.23
	82	113.57	145.62	93.95	67.89	152.38	147.72	144.78	139.11	103.79	122.16	82.33	104.82	125.71	119.84	112.48
	83	95.30	126.53	131.15	133.51	132.29	123.98	121.95	107.69	105.62	111.20	95.10	70.16	117.49	102.48	118.57
	84	76.15	83.52	102.83	113.03	0.0	0.0	0.0	82.12	78.23	73.77	0.0	0.0	94.66	79.66	77.18
	85	70.98	54.84	79.43	71.92	150.95	156.34	148.83	104.54	41.23	97.84	96.42	103.40	102.29	89.11	96.70
	86	82.84	105.20	106.82	137.64	120.82	129.86	121.44	104.54	78.55	105.15	77.27	109.79	109.59	65.39	88.17
	87	99.28	139.34	127.65	65.54	136.34	144.47	150.66	106.19	108.68	106.97	81.83	102.49	111.42	96.41	102.79
	88	87.40	112.51	102.25	111.15	120.82	122.56	126.00	91.39	105.02	89.62	69.98	62.37	101.37	110.11	85.74
	89	142.20	124.20	91.54	21.23	115.25	107.95	112.30	133.04	74.90	115.19	100.07	112.53	157.08	83.63	108.87
	90	66.10	30.74	53.16	133.31	131.55	134.20	138.56	119.93	23.76	89.32	81.61	90.40	150.37	101.56	79.97

BASELINE OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
T/C #	91	115.39	105.36	70.00	115.47	121.51	123.24	135.62	115.55	92.83	99.37	108.99	84.93	102.88	96.09	95.79
	92	120.87	108.15	91.90	114.55	109.64	114.11	123.95	122.86	92.83	110.33	113.55	53.98	106.53	97.91	97.01
	93	148.27	138.11	122.04	120.94	131.55	133.29	140.39	174.71	79.14	146.86	152.82	106.83	162.24	61.42	139.63
	94	144.62	87.70	35.47	138.30	95.94	104.07	141.30	139.66	98.31	70.17	119.95	73.08	60.91	83.30	59.31
	95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	96	202.02	75.24	57.08	84.92	101.77	95.28	90.51	152.70	116.49	141.18	111.11	77.94	138.41	201.89	111.40
	97	83.28	102.55	75.33	144.28	116.42	120.89	119.77	92.35	112.76	90.90	86.51	94.41	96.32	114.20	93.70
	98	104.33	106.43	0.0	57.70	0.0	0.0	0.0	113.05	144.78	111.97	0.0	0.0	100.94	120.64	112.95
	99	73.08	131.97	115.20	71.17	154.72	144.58	134.33	78.69	86.12	77.99	90.13	88.89	91.60	86.64	77.15
	100	81.61	118.57	102.33	66.07	187.06	182.41	156.65	93.80	107.44	87.46	102.40	66.51	117.49	100.66	84.48
	101	141.29	108.85	87.64	125.68	171.04	159.08	144.27	142.54	107.77	123.41	122.90	110.70	108.68	98.24	118.61
	102	135.13	91.95	84.50	20.75	31.73	29.19	37.76	123.11	103.40	104.14	92.62	34.81	114.05	98.74	98.55
	103	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	104	109.47	80.95	59.53	68.84	14.41	18.65	16.05	90.54	84.60	89.10	80.08	21.77	99.64	78.06	67.64
	105	157.00	110.52	96.51	105.18	36.09	33.54	43.38	161.61	124.69	142.31	98.26	42.30	146.57	101.25	146.95
	106	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	107	170.11	130.05	104.65	113.33	36.71	32.29	43.38	181.08	95.88	157.31	103.90	78.60	110.92	91.22	184.40
	108	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	109	46.72	55.74	64.16	31.92	20.93	30.43	32.03	19.56	59.71	60.63	96.17	74.88	84.34	58.41	31.64
	110	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	111	45.01	67.49	50.06	118.71	101.80	107.19	115.20	52.96	51.64	48.98	101.11	62.50	48.00	27.69	47.52
	112	71.47	126.16	103.18	177.24	0.0	0.0	0.0	89.67	79.94	88.23	0.0	0.0	82.68	64.96	94.68
	113	85.85	138.57	44.17	83.93	57.09	52.46	47.72	77.96	40.59	73.43	94.69	101.67	59.67	49.27	67.42
	114	55.17	121.51	49.04	151.78	166.99	147.72	135.64	86.50	59.08	81.98	70.48	102.99	96.48	51.41	78.40
	115	111.15	56.30	50.29	122.12	125.39	112.51	105.00	125.73	54.85	118.85	56.34	81.50	91.33	107.37	110.09
	116	99.86	100.12	70.08	95.38	109.64	104.98	98.39	106.05	88.27	92.97	60.67	81.29	110.18	90.61	101.88

BASELINE OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST T/C #	16	17	18	19
1	58.31	4.35	0.0	11.55
2	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0
4	124.74	110.33	155.54	213.39
5	45.95	81.15	47.09	15.94
6	0.0	0.0	0.0	0.0
7	79.45	79.35	73.72	71.03
8	0.0	52.34	53.35	55.79
9	116.61	46.90	44.88	43.62
10	117.33	59.51	50.32	54.98
11	72.79	52.34	55.76	53.02
12	54.58	52.34	53.95	54.06
13	56.03	50.35	51.23	50.43
14	58.22	0.0	0.0	0.0
15	133.77	21.75	24.21	19.87
16	82.64	59.60	63.09	60.48
17	130.12	97.44	96.83	93.29
18	91.40	119.86	114.17	106.07
19	36.80	109.61	103.48	93.29
20	78.99	69.07	55.73	54.12
21	42.60	66.94	56.73	61.39
22	117.97	0.0	0.0	0.0
23	153.77	87.11	89.65	0.0
24	47.95	187.33	190.98	192.91
25	33.47	104.45	105.16	108.93
26	18.59	131.85	120.69	115.23
27	29.86	109.02	0.0	0.0
28	0.0	0.0	0.0	0.0
29	105.55	51.44	52.15	63.17
30	170.57	86.45	92.22	98.72
31	61.04	133.52	132.40	134.34
32	64.68	132.60	135.05	132.51
33	45.05	109.77	109.57	106.94
34	47.96	107.03	90.40	91.42
35	20.55	96.99	75.80	77.74
36	159.44	68.22	63.01	66.31
37	155.79	90.09	85.24	87.27
38	52.14	84.02	85.33	82.71
39	47.78	109.25	97.19	100.04
40	45.60	108.35	109.34	99.13
41	59.41	109.25	102.57	99.13
42	26.10	0.0	0.0	0.0
43	149.04	133.41	93.95	101.37
44	165.11	146.29	109.61	106.84
45	151.25	130.57	93.51	96.80
46	31.69	109.57	55.91	69.45
47	54.68	135.24	63.47	34.94
48	64.34	116.05	133.33	100.45
49	25.94	89.59	75.71	65.85
50	19.62	153.26	117.46	117.58
51	114.80	121.52	92.81	90.20
52	17.49	87.55	60.92	71.96
53	61.53	55.67	47.11	46.52
54	97.27	112.19	54.60	79.25
55	20.33	123.15	90.08	85.64
56	0.0	0.0	0.0	0.0
57	0.0	121.32	120.20	123.05
58	65.60	128.62	133.25	130.35
59	30.03	88.45	85.51	81.06
60	8.66	36.04	40.35	41.37
61	73.52	47.60	49.41	49.52
62	106.37	76.81	75.60	75.91
63	67.69	54.16	50.32	50.43
64	38.61	152.69	156.14	125.20
65	123.54	26.20	27.78	30.60
66	111.85	67.65	67.65	56.84
67	108.20	70.59	73.38	62.30
68	0.0	0.0	0.0	0.0
69	0.0	0.0	0.0	0.0
70	101.90	0.0	0.0	0.0
71	81.45	52.51	49.58	46.98
72	147.93	74.35	72.32	56.06
73	109.21	122.72	117.03	101.62
74	109.94	73.44	67.77	55.15
75	0.0	0.0	0.0	0.0
76	112.86	161.82	132.40	105.12
77	0.0	65.99	56.09	56.81
78	61.04	123.47	101.35	91.42
79	108.47	145.39	108.65	89.60
80	213.44	85.55	80.77	79.97
81	217.81	145.79	125.41	124.70
82	144.83	120.22	101.75	100.04
83	119.99	86.45	72.57	67.22
84	124.37	0.0	0.0	0.0
85	44.71	111.50	97.60	95.89
86	119.08	119.71	112.20	108.67
87	50.51	114.24	105.07	102.28
88	111.78	71.36	64.78	57.62
89	98.63	135.24	114.03	105.93
90	134.53	85.72	59.10	77.43
91	122.11	79.34	82.78	84.72
92	111.88	58.40	56.38	58.32
93	121.38	127.71	124.77	112.10
94	124.30	71.14	79.13	80.17
95	0.0	0.0	0.0	0.0
96	154.14	75.09	74.89	76.82
97	143.27	97.94	100.48	92.37
98	60.31	0.0	0.0	0.0
99	69.06	105.20	101.35	86.86
100	66.70	77.33	74.39	63.58
101	96.44	0.0	0.0	108.67
102	11.22	43.46	37.08	32.80
103	0.0	0.0	0.0	0.0
104	58.99	34.10	28.36	23.48
105	109.11	53.46	46.44	40.90
106	0.0	0.0	0.0	0.0
107	112.62	91.05	74.62	69.69
108	0.0	0.0	0.0	0.0
109	34.36	79.33	86.42	81.06
110	0.0	0.0	0.0	0.0
111	76.80	66.03	65.83	62.30
112	127.47	0.0	0.0	0.0
113	78.54	107.03	97.70	96.98
114	111.95	131.18	86.24	83.62
115	105.93	96.69	83.00	74.92
116	92.16	108.54	104.68	78.34

BIASED FIRING OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
T/C # 1	74.10	126.33	7.17	35.79	97.13	121.79	46.10	0.0	0.0	20.46	104.12	121.39	79.91	13.98	71.66
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	52.71	0.0	29.43	43.82	54.27	0.0	0.0	0.0	0.0	85.85	0.0	152.97	143.05	0.0
4	95.10	233.33	33.70	147.07	47.00	193.90	77.05	27.54	0.0	51.11	67.60	83.95	195.84	154.92	152.01
5	30.47	121.07	112.26	36.72	50.09	99.87	34.32	14.20	64.16	26.71	137.00	89.43	79.91	110.17	58.91
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	125.33	20.07	39.43	18.17	104.43	15.51	0.0	80.56	8.19	135.78	125.96	105.48	130.27	93.56
8	96.20	139.32	33.14	129.00	31.87	39.10	114.74	65.00	0.0	61.43	85.44	34.08	6.13	31.21	0.0
9	77.94	81.97	43.14	62.35	32.77	23.68	80.95	43.20	122.87	50.53	76.92	54.04	17.52	36.63	115.74
10	111.73	138.39	33.00	33.10	44.54	38.20	93.73	53.18	23.76	56.89	106.14	58.60	22.87	49.33	111.17
11	75.20	70.12	38.30	24.27	47.26	49.08	65.45	68.64	25.55	45.99	75.71	117.01	26.47	66.61	75.57
12	45.15	94.43	91.43	53.23	61.81	38.20	58.17	64.09	39.96	39.65	40.51	60.42	37.31	71.17	71.01
13	82.50	45.61	72.27	34.19	58.35	47.26	53.62	36.87	90.00	37.85	87.87	73.18	28.27	64.79	62.81
14	49.69	57.37	44.95	39.62	0.0	0.0	0.0	0.0	0.0	0.0	52.62	75.01	83.74	0.0	0.0
15	107.08	91.34	30.39	92.39	31.87	40.00	95.54	47.79	15.81	98.86	111.56	65.81	117.46	47.49	60.08
16	104.34	161.37	144.28	141.72	59.07	61.80	130.25	72.34	0.0	34.28	59.23	43.07	76.37	125.61	59.17
17	65.10	70.03	80.80	54.07	111.07	112.90	156.73	111.57	0.0	137.21	66.52	58.53	56.31	113.14	141.30
18	111.65	57.23	43.79	30.46	61.80	64.53	123.86	86.01	48.15	107.07	113.99	43.07	74.54	63.86	81.04
19	76.04	41.34	31.24	47.73	92.81	92.81	110.16	71.43	81.83	89.73	78.68	66.72	89.14	89.40	26.57
20	72.39	51.22	33.81	41.37	60.89	51.79	101.94	45.07	86.39	87.91	72.60	61.26	39.96	64.77	80.12
21	56.90	85.23	19.62	63.02	21.99	22.89	59.07	99.70	65.42	53.30	39.85	22.30	10.39	24.01	50.08
22	0.0	0.0	137.08	0.0	0.0	0.0	191.49	0.0	25.41	0.0	0.0	0.0	145.82	0.0	113.08
23	111.70	149.34	33.87	147.25	97.15	129.42	188.75	101.95	106.58	177.50	105.22	65.87	22.86	98.00	150.52
24	148.24	251.01	119.73	110.72	219.74	247.96	217.01	136.35	0.0	279.49	127.14	95.07	125.73	209.96	42.00
25	68.80	50.97	70.42	45.97	116.63	117.55	144.03	72.46	0.0	146.46	69.92	62.22	69.12	110.48	22.19
26	100.74	111.79	47.06	139.03	50.97	29.25	148.60	104.39	120.28	167.46	104.00	71.34	115.68	63.95	19.52
27	91.61	91.09	34.67	139.95	160.47	206.08	143.12	93.43	115.71	150.11	90.61	116.99	78.24	116.87	32.96
28	44.23	130.06	133.77	111.93	0.0	0.0	0.0	0.0	0.0	0.0	46.86	86.85	44.55	0.0	0.0
29	64.03	101.34	106.73	127.37	44.44	39.91	109.14	49.57	148.42	118.90	59.09	38.38	68.00	86.55	86.11
30	93.23	96.03	101.25	98.03	101.84	140.20	156.63	79.60	182.19	167.30	101.06	81.16	152.92	91.12	160.38
31	90.49	91.79	102.16	39.50	142.94	161.27	115.54	107.88	0.0	222.01	87.66	104.90	97.20	124.91	61.80
32	96.88	86.92	118.00	94.07	61.70	58.06	157.54	91.45	150.25	169.12	97.40	80.25	88.07	59.21	67.27
33	84.10	80.34	80.64	102.94	57.15	54.43	38.10	94.19	49.01	157.25	86.45	51.09	89.90	55.57	46.35
34	95.97	103.97	70.22	126.04	153.89	142.02	132.89	56.84	52.64	139.91	87.66	55.64	86.25	121.25	50.89
35	133.42	111.28	52.91	127.87	29.07	31.78	100.92	144.41	40.86	103.38	136.37	98.51	47.06	29.30	20.23
36	93.55	119.62	72.36	127.28	107.68	124.12	102.20	93.69	163.43	178.65	90.12	69.62	84.74	94.21	96.82
37	82.50	85.72	80.05	81.02	78.47	86.68	165.21	80.01	145.17	164.96	87.69	62.33	88.39	69.58	127.87
38	127.34	136.87	118.72	137.45	89.42	94.89	201.70	106.47	52.13	214.22	124.22	95.18	116.70	84.17	60.35
39	59.80	74.77	47.77	67.03	98.55	85.77	133.25	65.43	148.82	153.09	64.58	69.62	134.97	104.26	35.26
40	84.42	56.33	133.22	63.38	78.47	93.07	145.13	71.80	142.43	165.87	79.17	61.42	105.74	74.14	53.08
41	120.03	60.19	37.37	39.63	166.12	156.08	149.69	81.83	132.38	158.57	127.87	78.74	120.36	151.75	64.90
42	70.73	55.33	104.31	71.58	0.0	0.0	0.0	0.0	0.0	0.0	71.87	49.59	112.14	0.0	0.0
43	94.78	153.93	72.68	135.11	208.44	192.86	161.92	88.62	152.87	171.76	91.36	60.83	86.89	183.14	132.81
44	110.31	140.34	73.39	134.09	233.04	196.59	176.53	95.92	174.78	185.45	104.75	84.54	168.16	194.99	128.24
45	118.53	145.41	137.43	147.52	232.13	168.31	168.31	128.79	176.60	200.95	108.41	84.54	170.90	184.05	120.93

Wisconsin Power & Light Co.
Columbia #1

C-E Power Systems
Field Testing and
Performance Results

BIASED FIRING OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
T/C #															
46	71.06	62.04	75.42	89.25	37.02	40.64	102.56	54.93	111.78	53.17	59.74	141.17	0.0	41.76	31.71
47	88.39	33.51	111.02	135.68	177.44	159.18	169.23	84.98	130.04	150.76	81.62	62.65	76.85	155.76	48.60
48	93.87	89.34	102.60	113.47	153.71	150.05	156.45	70.40	137.35	145.28	87.71	74.51	88.71	142.97	67.09
49	105.74	66.23	37.23	134.77	139.10	123.57	124.48	54.93	103.56	45.91	95.01	70.86	128.90	126.54	33.52
50	162.04	143.26	133.39	143.72	177.17	177.17	153.44	136.63	108.81	158.76	156.19	41.42	113.96	167.35	13.63
51	144.09	202.37	35.05	33.38	152.52	142.48	29.54	82.03	112.46	49.32	137.93	123.49	113.96	141.79	107.88
52	179.36	170.04	124.40	131.94	135.17	150.70	43.09	105.01	123.42	162.41	158.62	150.89	113.04	111.65	20.71
53	57.06	79.95	135.22	80.72	40.37	48.53	19.70	56.54	86.91	88.46	50.33	86.96	79.26	27.95	40.49
54	65.26	77.31	62.39	60.72	75.83	75.83	135.17	56.54	53.22	36.65	63.68	99.74	78.35	46.93	89.62
55	105.42	89.63	123.95	115.41	131.52	127.87	137.91	121.27	93.29	107.62	90.44	82.39	124.92	123.52	24.28
56	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	169.98	128.93	0.0	39.40	135.49	111.74	53.37	142.24	89.69	35.71	134.57	117.74	0.0	120.22	0.0
58	194.61	143.60	169.70	105.38	148.27	129.09	53.37	129.45	96.08	42.04	177.16	143.31	129.22	141.23	88.08
59	94.19	102.17	36.09	33.14	105.35	88.00	34.32	103.88	63.25	29.41	104.12	84.86	63.49	103.78	38.94
60	90.72	54.04	53.50	26.07	70.01	67.27	86.43	54.08	35.44	63.25	84.23	29.56	66.41	68.43	6.32
61	83.41	93.24	31.36	32.42	45.45	31.87	59.08	54.99	37.25	45.08	81.79	35.89	61.85	48.42	99.30
62	108.07	99.35	74.09	86.07	189.59	215.11	92.82	90.52	0.0	75.09	96.40	72.27	111.14	164.30	151.35
63	74.29	53.11	53.15	25.17	80.04	80.95	78.21	54.99	131.09	55.97	72.06	67.71	57.30	79.38	89.26
64	91.63	95.06	43.59	91.55	163.13	141.22	66.37	60.82	111.00	10.23	87.87	92.35	95.61	126.86	47.36
65	48.71	88.91	131.03	124.36	40.00	35.48	97.37	40.55	51.78	76.96	44.69	145.25	128.42	37.52	130.34
66	67.83	97.45	53.10	98.79	136.64	103.76	127.51	84.19	102.82	83.35	62.88	46.70	14.79	123.18	114.81
67	140.36	155.83	57.04	73.23	141.21	132.99	126.60	67.76	0.0	98.86	133.48	136.12	72.72	121.36	112.99
68	0.0	0.0	71.28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
69	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70	73.36	127.02	111.51	155.47	0.0	0.0	0.0	0.0	0.0	0.0	69.92	135.26	154.04	0.0	0.0
71	87.04	94.74	51.30	98.84	204.26	154.99	149.51	76.11	45.55	134.59	82.09	88.68	45.45	183.52	91.16
72	149.15	170.23	137.83	162.77	90.15	93.80	210.64	105.30	69.18	180.24	133.23	108.77	128.47	83.09	181.55
73	106.22	120.32	118.32	130.14	122.12	127.60	180.55	97.09	93.80	178.41	110.09	80.46	119.34	111.40	148.70
74	52.40	54.51	35.94	149.42	108.41	64.62	127.60	153.70	69.18	119.98	52.92	18.78	42.73	89.48	107.60
75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	93.23	114.43	76.60	104.12	188.57	170.32	150.24	91.45	104.86	158.17	84.01	76.60	60.71	168.73	131.16
77	82.27	94.23	0.0	105.03	211.36	150.24	168.50	84.16	58.10	160.00	81.58	0.0	0.0	193.37	0.0
78	68.59	83.34	34.82	123.33	43.98	53.52	141.11	81.42	57.18	125.29	69.42	67.48	80.77	40.14	111.98
79	44.02	39.57	33.60	49.03	76.28	75.37	116.45	62.29	32.73	43.29	45.15	32.05	58.89	57.39	93.72
80	78.03	72.34	33.57	67.93	155.17	187.11	152.43	116.51	220.88	226.06	84.04	55.05	70.14	72.32	230.95
81	128.26	106.42	110.70	173.84	287.22	253.60	206.26	114.68	233.64	257.01	130.31	225.66	166.93	262.92	206.36
82	96.29	94.24	123.37	33.31	222.65	190.76	154.26	82.74	136.95	153.09	101.08	69.62	134.97	198.28	154.36
83	104.51	103.33	120.75	76.14	177.98	158.82	151.52	92.78	162.52	125.70	104.73	184.65	166.93	164.53	127.87
84	102.03	119.32	76.09	73.40	0.0	0.0	0.0	0.0	0.0	0.0	101.08	167.32	90.22	0.0	0.0
85	129.49	142.37	94.33	134.31	169.23	170.14	129.05	89.54	154.70	159.89	118.15	71.77	133.47	149.37	47.09
86	103.91	115.22	133.34	94.72	199.33	173.79	164.60	77.68	156.52	129.76	103.54	71.77	158.12	182.23	115.45
87	104.83	91.83	113.76	31.94	213.91	197.50	168.31	73.13	168.39	141.63	109.63	99.15	126.16	194.08	51.63
88	76.35	72.35	131.28	55.42	164.60	145.49	141.84	74.04	131.87	127.02	75.54	136.60	113.37	147.54	115.45
89	58.32	52.17	144.52	74.04	143.23	129.05	120.83	97.75	102.65	121.54	65.82	149.38	122.51	129.28	103.58
90	135.65	150.57	148.13	142.31	131.01	169.87	167.13	92.06	106.99	145.06	136.71	66.89	66.49	157.31	130.71

Wisconsin Power & Light Co.
Columbia #1

C-E Power Systems
Field Testing and
Performance Results

BIASED FIRING OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
T/C # 91	115.46	121.54	109.79	125.37	140.13	152.52	132.43	112.14	120.68	135.93	108.70	108.87	82.00	146.35	109.71
92	93.54	135.51	107.05	140.99	134.26	147.05	140.65	133.14	123.42	124.97	84.35	87.87	122.18	137.22	103.32
93	99.94	114.03	152.71	146.47	139.74	138.83	134.26	77.47	127.08	145.98	91.65	149.06	155.97	133.57	124.32
94	78.94	87.25	52.33	122.72	111.43	129.69	130.61	54.72	103.33	103.06	74.62	79.66	101.17	124.43	145.32
95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
96	129.08	138.50	127.06	127.17	162.22	174.09	100.12	105.12	128.35	78.74	114.67	143.50	133.06	137.82	169.61
97	211.12	64.58	93.19	57.73	148.52	167.68	174.99	80.92	71.80	101.60	140.78	66.72	103.76	124.10	132.17
98	118.10	125.19	97.81	121.68	0.0	0.0	0.0	0.0	0.0	0.0	118.62	76.81	170.47	0.0	0.0
99	100.53	133.97	88.40	127.69	96.36	101.84	194.96	86.89	61.73	153.60	101.06	72.04	75.29	96.59	67.27
100	126.43	135.05	113.44	134.67	145.13	159.73	150.60	95.51	178.94	178.65	118.13	108.88	88.39	107.00	55.80
101	0.0	141.75	111.94	78.29	130.88	145.49	87.04	0.0	143.74	151.68	121.80	133.86	95.10	104.62	47.09
102	103.89	111.39	113.03	128.90	103.66	123.70	121.19	92.28	0.0	36.59	98.21	91.22	126.65	81.24	10.74
103	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
104	88.80	103.54	89.97	102.61	86.11	99.90	83.60	77.86	65.54	21.68	82.34	114.40	99.72	59.94	51.73
105	97.00	107.71	125.67	143.91	113.05	128.08	95.51	97.29	0.0	35.97	92.36	124.41	147.28	86.88	74.28
106	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
107	85.09	89.33	94.36	119.51	96.14	116.81	82.35	100.42	0.0	34.72	82.34	123.16	170.38	83.12	71.78
108	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
109	112.45	111.93	80.30	73.57	69.76	84.35	36.13	92.93	55.07	23.14	88.29	84.86	61.67	93.73	44.37
110	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	84.52	0.0	0.0	0.0	0.0	0.0	0.0
111	87.91	90.12	44.88	31.42	123.86	123.86	57.25	108.83	60.87	104.33	115.21	107.80	36.33	116.79	49.17
112	84.31	77.79	79.55	57.61	0.0	0.0	0.0	0.0	0.0	0.0	89.39	106.94	78.24	0.0	0.0
113	103.27	105.19	59.28	148.87	62.62	56.24	158.46	88.72	0.0	59.62	96.18	170.65	38.90	67.40	66.36
114	63.44	61.49	91.52	98.82	143.30	149.69	162.47	67.25	157.04	179.56	64.58	101.57	146.84	128.00	106.87
115	59.21	52.95	87.28	52.73	151.88	108.05	116.26	51.30	126.39	124.28	56.10	56.28	127.07	120.14	85.33
116	68.91	90.29	110.70	116.32	97.73	106.86	104.12	58.36	92.38	120.41	63.68	106.13	107.56	104.34	82.32

BIASED FIRING OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST		16	17	18
T/C #	1	44.29	4.33	23.33
	2	0.0	0.0	0.0
	3	0.0	0.0	0.0
	4	83.14	29.39	47.90
	5	45.50	11.64	21.06
	6	0.0	0.0	0.0
	7	25.03	0.0	0.0
	8	97.39	55.06	57.49
	9	91.31	45.99	52.04
	10	93.74	57.79	52.04
	11	75.49	65.97	40.60
	12	71.84	65.97	35.04
	13	64.55	38.74	34.84
	14	0.0	0.0	0.0
	15	79.73	45.14	87.01
	16	115.03	71.50	29.49
	17	158.87	110.73	129.61
	18	127.21	72.40	97.65
	19	117.47	74.23	83.05
	20	112.60	48.75	80.31
	21	67.58	89.73	45.75
	22	0.0	0.0	553.17
	23	169.60	0.0	157.16
	24	208.51	134.59	255.56
	25	135.52	72.53	134.29
	26	147.69	98.07	148.90
	27	136.74	0.0	139.77
	28	0.0	0.0	0.0
	29	57.16	51.46	126.82
	30	97.28	79.06	150.96
	31	145.99	103.39	215.34
	32	165.46	90.61	161.52
	33	121.63	92.43	152.39
	34	132.59	58.72	132.30
	35	99.71	124.39	104.00
	36	63.28	84.54	171.06
	37	124.12	78.26	150.10
	38	152.13	104.71	231.16
	39	119.25	34.03	134.24
	40	120.47	66.41	154.02
	41	136.30	79.17	144.58
	42	0.0	0.0	0.0
	43	146.10	85.03	162.34
	44	157.06	97.32	132.41
	45	133.93	114.26	139.71

TEST		16	17	18
T/C #	46	110.79	55.01	50.15
	47	127.84	75.93	138.00
	48	129.05	66.35	123.99
	49	115.06	47.73	51.06
	50	144.00	134.13	151.16
	51	28.64	69.35	46.31
	52	35.85	93.96	150.25
	53	27.44	51.17	88.17
	54	119.65	54.80	43.60
	55	123.30	40.50	100.03
	56	0.0	0.0	0.0
	57	63.69	128.01	39.03
	58	61.26	125.86	43.55
	59	40.67	88.43	32.71
	60	96.17	49.01	52.95
	61	69.41	52.33	44.79
	62	113.22	91.50	75.70
	63	93.74	59.60	53.86
	64	73.06	55.97	12.55
	65	111.38	46.04	66.64
	66	132.08	79.70	76.67
	67	135.74	61.48	94.00
	68	0.0	0.0	0.0
	69	0.0	0.0	0.0
	70	0.0	0.0	0.0
	71	148.91	76.13	121.51
	72	206.08	100.81	150.25
	73	173.25	89.85	175.29
	74	122.12	36.22	123.33
	75	0.0	0.0	0.0
	76	150.86	90.61	144.18
	77	155.73	76.95	152.39
	78	135.03	76.93	124.09
	79	109.45	58.72	34.86
	80	142.39	108.36	202.07
	81	193.50	108.35	149.15
	82	142.39	80.03	153.54
	83	143.61	83.72	91.62
	84	0.0	0.0	0.0
	85	120.53	82.31	159.60
	86	130.27	58.03	59.24
	87	163.15	62.27	144.39
	88	129.05	63.19	119.42
	89	120.53	86.87	114.35
	90	105.03	79.37	133.31

TEST		16	17	18
T/C #	91	118.43	109.48	127.42
	92	125.74	116.78	124.08
	93	136.70	43.92	141.12
	94	146.44	49.35	66.30
	95	0.0	0.0	0.0
	96	104.70	99.71	79.35
	97	171.04	87.91	101.30
	98	0.0	0.0	0.0
	99	178.85	90.61	162.44
	100	109.51	95.59	182.01
	101	70.63	117.91	157.77
	102	129.12	86.06	35.77
	103	0.0	0.0	0.0
	104	53.95	64.75	17.78
	105	75.67	86.69	38.89
	106	0.0	0.0	0.0
	107	49.78	87.31	35.15
	108	0.0	0.0	0.0
	109	38.25	89.34	22.85
	110	0.0	0.0	0.0
	111	53.01	113.46	89.43
	112	0.0	0.0	0.0
	113	131.37	87.87	59.33
	114	141.17	68.23	157.37
	115	82.79	54.10	125.81
	116	96.51	55.71	113.72

OVERFIRE AIR OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
T/C #	1	72.87	70.26	0.0	7.74	6.58	74.77	28.41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	3	114.87	129.93	0.0	11.22	9.0	41.08	0.0	0.0	0.0	0.0	0.0	129.64	127.80	103.85	84.77
	4	141.36	41.15	100.75	77.27	124.43	163.35	133.22	114.46	4.58	6.01	0.0	0.0	0.0	0.0	0.0
	5	82.90	92.15	93.05	55.13	44.15	74.77	46.53	33.34	0.0	0.0	0.0	87.99	91.26	93.80	62.87
	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	7	115.78	115.32	0.0	11.22	8.30	100.33	0.0	0.0	0.0	0.0	0.0	123.80	119.57	120.29	29.29
	8	95.96	92.93	0.0	2.39	0.0	53.06	51.24	25.40	34.64	38.27	28.59	0.0	0.0	0.0	20.50
	9	29.43	29.39	0.14	0.0	84.41	75.85	43.97	21.81	31.92	18.48	15.48	61.52	58.58	80.27	6.44
	10	24.93	29.07	37.33	29.25	88.07	132.47	105.07	51.67	84.08	82.86	55.17	155.02	127.96	123.20	34.00
	11	81.26	83.24	2.83	0.0	28.03	93.19	65.81	18.23	72.82	67.36	60.02	54.96	47.66	43.83	85.87
	12	20.46	19.12	37.32	61.03	47.96	89.54	56.70	60.77	80.12	91.08	74.60	100.22	99.64	107.67	26.78
	13	87.65	91.75	68.26	52.83	74.38	79.49	53.97	55.31	74.64	71.92	72.17	86.34	66.78	110.41	109.62
	14	77.01	95.41	54.39	53.74	65.26	78.58	58.52	47.12	72.82	78.30	58.81	117.02	115.17	107.67	40.34
	15	130.51	142.24	122.04	102.01	107.17	131.46	112.28	120.02	70.95	63.68	42.42	28.41	24.05	26.56	14.22
	16	6.33	10.22	105.50	102.92	0.0	132.38	95.84	63.42	56.37	52.75	55.75	0.0	0.0	0.0	36.65
	17	59.31	64.32	79.12	70.97	26.16	134.20	115.02	96.27	71.86	67.32	56.96	136.38	175.34	50.11	52.99
	18	43.85	52.19	27.31	63.63	40.62	94.93	62.08	37.06	30.08	36.42	29.16	132.65	105.95	111.23	44.81
	19	89.41	93.52	70.91	69.23	56.07	82.14	75.75	67.98	68.21	62.77	58.17	95.38	105.03	91.14	76.68
	20	69.33	74.05	73.21	77.35	108.99	107.71	94.01	92.62	83.72	92.87	73.96	101.96	105.03	85.66	91.28
	21	28.47	38.87	51.73	44.57	50.61	72.11	50.24	37.06	61.83	37.33	27.96	36.36	31.26	30.16	30.32
	22	148.83	156.09	122.09	116.67	128.22	150.68	122.37	114.59	128.54	138.60	134.61	0.0	184.20	0.0	93.17
	23	19.55	26.33	179.61	111.19	7.03	127.85	145.20	156.60	4.58	7.71	0.0	197.85	188.16	172.45	33.09
	24	138.78	146.86	157.62	81.06	76.17	211.79	178.97	146.55	74.66	79.25	68.87	0.0	0.0	0.0	113.26
	25	50.26	56.73	65.49	53.71	52.48	125.11	97.71	70.76	38.28	43.75	37.37	0.0	0.0	0.0	17.83
	26	0.0	88.41	0.0	0.0	0.0	112.63	0.0	0.0	73.45	70.13	0.0	137.99	139.79	133.20	0.0
	27	59.36	52.15	0.0	0.0	0.0	128.46	0.0	58.00	0.0	64.66	44.01	138.73	137.96	134.11	350.71
	28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	29	19.35	23.59	246.19	109.75	104.26	105.71	132.20	86.06	22.17	9.54	21.28	112.39	96.64	136.64	0.0
	30	55.51	59.93	132.69	143.85	128.92	115.76	92.92	82.41	47.45	56.27	55.63	186.15	114.91	227.83	78.36
	31	108.43	103.72	137.26	94.54	82.35	180.58	160.51	110.72	79.02	73.58	75.67	195.64	173.35	216.91	86.57
	32	111.17	115.93	134.00	129.25	62.28	153.20	130.57	138.12	52.60	57.18	56.24	56.90	60.15	59.95	73.80
	33	91.08	97.05	109.09	113.29	73.22	117.59	97.49	111.63	67.17	68.11	63.52	53.26	96.64	59.04	44.66
	34	142.23	139.04	116.22	110.98	111.57	117.59	104.80	120.77	73.55	77.23	76.89	78.05	76.56	94.62	90.22
	35	101.12	95.29	77.15	51.03	62.28	104.80	98.40	105.24	34.46	35.40	32.06	62.73	49.22	74.54	74.71
	36	63.12	64.31	65.53	45.03	46.04	121.55	98.71	65.39	47.49	46.62	46.59	135.53	58.63	220.86	44.99
	37	77.71	80.61	82.00	50.17	98.18	117.89	112.41	89.11	56.58	58.44	57.49	82.20	56.81	122.33	66.83
	38	95.05	96.44	143.07	142.35	175.80	189.10	183.62	150.30	135.06	119.57	87.88	205.61	181.86	229.96	98.76
	39	110.58	114.70	55.62	72.03	0.0	114.24	0.0	0.0	29.39	56.62	62.35	83.66	83.25	73.93	48.62
	40	73.15	72.13	127.49	133.21	94.53	139.81	134.33	91.85	100.36	89.44	95.18	93.15	97.86	89.45	51.65
	41	91.40	95.22	115.10	150.43	110.56	154.33	121.85	135.69	62.95	64.81	68.42	120.92	118.87	106.80	48.62
	42	107.84	138.56	86.39	100.33	55.61	118.81	92.32	131.13	66.60	69.36	67.21	111.42	97.86	110.46	93.29
	43	57.93	56.33	143.61	149.37	0.0	120.94	63.43	131.74	81.53	88.87	74.55	189.33	182.18	175.59	34.45
	44	81.58	37.15	153.59	158.22	156.81	184.84	114.55	133.26	108.00	107.13	98.28	213.39	167.58	233.91	54.40
	45	110.29	101.33	33.23	102.47	107.94	191.23	151.08	146.96	94.30	99.82	100.10	181.31	161.19	191.10	72.62

OVERFIRE AIR OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

Test	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
T/C #															
46	91.92	93.71	91.40	77.34	94.13	104.50	98.11	0.0	46.31	40.62	59.97	138.95	115.53	135.43	73.53
47	70.94	93.87	93.53	104.91	112.20	126.73	141.03	119.56	67.84	86.74	85.49	179.85	162.10	178.33	112.79
48	116.33	119.00	117.32	117.09	135.95	128.25	140.51	121.39	93.39	87.96	83.06	184.95	176.70	182.89	107.31
49	57.09	61.13	52.24	47.76	57.45	109.07	0.0	0.0	25.23	0.0	0.0	158.68	142.02	159.17	85.40
50	39.49	40.87	91.11	122.24	134.71	165.34	145.20	157.59	39.27	30.39	0.0	184.26	190.96	172.52	18.87
51	81.36	85.79	55.55	65.54	0.0	155.31	63.09	46.26	46.62	43.96	31.28	163.09	159.03	152.44	0.0
52	90.49	91.03	55.77	0.0	0.0	175.28	74.03	53.53	73.01	53.03	38.50	138.98	101.49	111.34	15.90
53	58.57	62.09	0.0	15.03	0.0	57.63	0.0	0.0	0.0	0.0	0.0	102.45	91.44	93.99	0.0
54	61.30	66.33	15.18	20.35	0.0	129.73	41.27	20.98	24.04	22.32	19.92	127.29	106.06	136.92	18.87
55	93.23	84.55	22.06	13.25	15.00	128.82	34.02	28.16	14.26	18.75	2.68	158.71	158.11	144.22	12.67
56	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	109.91	115.92	0.0	0.0
58	141.36	161.57	131.09	116.54	118.95	101.25	101.25	108.06	164.83	160.26	161.42	136.95	154.28	123.95	174.26
59	73.78	78.79	61.70	58.12	60.52	52.90	47.44	46.95	94.51	106.38	94.45	87.26	96.74	77.37	84.77
60	13.34	16.74	50.41	49.19	57.06	67.64	61.25	58.95	36.45	61.89	60.02	57.15	52.21	65.68	45.78
61	78.53	74.75	77.58	77.44	92.63	75.85	71.28	63.50	18.46	14.93	11.96	76.11	72.25	105.84	22.29
62	31.20	85.58	182.38	120.36	147.43	166.25	128.81	112.80	119.38	120.30	109.90	0.0	0.0	0.0	158.93
63	32.14	31.09	120.30	109.40	117.29	106.89	92.28	91.79	143.13	144.96	126.95	133.83	117.00	145.12	64.89
64	104.09	92.93	99.29	116.71	104.51	99.58	76.76	74.45	81.94	84.69	79.47	152.82	173.61	127.77	53.05
65	145.12	65.34	155.01	129.42	101.05	136.03	127.81	139.20	145.82	102.91	111.69	26.96	30.36	19.39	72.12
66	112.24	114.22	122.04	117.54	72.47	122.33	116.85	116.37	61.83	61.86	56.96	53.79	69.43	34.68	46.63
67	52.03	59.47	135.74	124.89	41.53	117.76	123.24	132.81	112.94	119.35	109.26	0.0	0.0	0.0	58.45
68	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
69	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70	175.29	185.80	148.58	145.90	165.66	149.77	136.99	117.33	175.10	176.03	167.48	124.84	80.42	127.72	117.83
71	52.08	50.75	115.69	63.75	75.26	178.97	156.16	115.50	44.62	45.56	47.04	81.74	64.00	155.11	63.06
72	129.65	132.25	180.90	145.90	69.78	214.52	169.85	217.69	118.49	115.77	99.29	212.43	196.36	226.23	75.82
73	97.68	104.23	178.59	155.03	78.91	201.77	178.97	181.23	96.57	102.98	91.99	109.50	116.04	89.36	56.69
74	32.15	146.35	133.53	83.80	91.69	154.33	131.50	146.55	71.01	79.25	64.02	129.96	134.31	126.80	105.04
75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	80.13	81.81	74.59	68.07	118.88	160.21	75.58	82.41	103.67	91.83	89.05	113.12	102.12	118.37	56.48
77	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.89	100.29	111.97	0.0
78	90.17	95.60	79.87	68.07	99.69	139.51	111.19	92.45	48.97	50.82	44.12	115.31	105.78	113.80	51.93
79	57.33	63.57	149.71	33.50	117.05	143.16	113.93	134.47	107.33	105.53	91.49	112.39	110.34	95.53	104.83
80	90.49	89.13	150.59	70.21	117.36	213.70	136.16	98.24	67.51	62.99	47.80	94.61	109.74	93.10	52.26
81	154.42	159.75	105.00	71.12	94.53	153.51	141.64	124.73	93.96	91.26	108.58	149.42	158.14	137.86	54.08
82	85.01	84.25	23.56	35.50	18.26	116.98	37.67	62.65	22.21	17.79	11.89	180.81	159.96	185.32	13.52
83	135.24	137.54	93.22	68.59	100.92	140.21	67.68	95.50	81.19	76.66	41.75	100.46	102.43	103.15	84.16
84	103.27	104.95	55.59	20.55	72.62	134.33	45.23	43.55	58.40	52.98	27.30	80.01	79.60	78.49	74.12
85	68.00	79.93	0.0	79.65	0.0	157.47	43.42	7.20	102.52	62.42	45.43	110.46	108.22	140.91	0.0
86	112.73	111.07	40.73	35.97	0.0	162.03	67.99	63.88	64.20	52.42	51.48	148.45	109.13	188.36	69.89
87	111.81	112.24	63.16	73.20	52.90	169.33	83.50	73.00	63.29	69.71	57.54	187.14	163.93	191.10	0.0
88	101.77	108.54	52.24	40.50	64.73	142.80	53.41	71.17	34.24	29.78	21.39	109.73	110.05	109.85	59.87
89	80.77	81.55	25.23	15.55	62.91	152.82	67.07	48.41	38.76	41.53	16.64	117.03	103.65	127.21	68.98
90	55.34	56.52	11.42	63.62	0.0	177.21	56.72	0.0	0.0	0.0	0.0	177.69	167.24	168.87	0.0

OVERFIRE AIR OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
T/C #	91	129.76	129.63	33.77	30.16	0.0	144.35	47.62	37.19	7.30	0.0	51.80	174.77	160.85	180.73	27.82
	92	126.11	122.32	41.01	43.02	57.12	133.39	55.81	31.77	52.07	41.24	50.59	162.36	145.33	181.64	14.43
	93	155.33	145.46	0.0	0.0	93.60	43.99	0.0	0.0	83.05	79.45	94.34	198.12	175.45	206.26	0.0
	94	142.55	129.63	66.55	63.23	81.73	178.12	123.34	94.57	112.27	89.49	97.99	168.20	169.98	157.00	66.84
	95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	96	117.79	116.12	129.30	101.18	112.73	149.82	127.90	99.10	90.16	91.99	101.38	163.05	146.23	151.51	51.23
	97	76.63	67.87	80.99	67.23	46.06	153.38	144.25	112.71	135.77	136.70	133.62	113.65	122.39	97.53	113.20
	98	319.88	104.64	59.11	287.05	0.0	70.02	93.14	58.00	141.32	145.00	151.65	223.36	222.78	111.28	538.57
	99	82.86	86.03	83.03	39.05	63.19	113.93	99.32	86.97	109.15	119.23	142.63	196.36	194.32	202.33	66.50
	100	98.70	106.13	131.32	129.56	149.33	158.07	144.38	143.91	155.15	117.74	106.14	236.20	253.81	226.32	76.85
	101	91.72	90.37	109.71	116.17	109.46	127.33	122.77	117.74	81.53	84.31	86.71	171.09	179.44	173.77	83.57
	102	153.72	148.42	52.09	37.13	76.98	139.32	76.08	70.75	27.23	25.41	0.0	0.0	0.0	0.0	19.90
	103	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	104	106.80	93.55	9.81	14.14	60.69	119.30	36.63	23.85	11.78	16.74	0.0	100.10	159.98	109.20	66.12
	105	134.34	165.91	53.54	109.16	105.80	138.69	81.71	57.59	91.68	71.04	44.94	0.0	0.0	0.0	23.00
	106	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.31	0.0	0.0	0.0	0.0	0.0	119.37
	107	141.85	171.73	64.62	128.35	113.32	144.94	99.89	58.22	97.95	61.64	29.13	0.0	0.0	0.0	54.85
	108	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	109	59.19	60.55	49.87	63.54	58.70	58.36	48.34	43.31	47.11	50.74	54.33	74.12	68.44	70.07	104.86
	110	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.52	121.57	91.23	0.0
	111	54.76	55.63	46.32	23.23	33.37	103.14	78.49	56.13	27.37	26.50	33.98	66.18	72.17	54.66	94.02
	112	62.10	62.65	79.17	91.10	107.21	106.84	90.40	77.15	68.28	69.22	59.16	107.30	103.25	99.40	104.13
	113	64.62	64.75	77.95	59.97	128.92	135.85	109.36	94.28	145.69	132.01	124.37	0.0	0.0	0.0	79.27
	114	54.02	52.57	139.54	124.03	75.36	149.86	143.47	144.82	88.49	80.31	67.21	159.64	147.18	190.79	86.90
	115	62.53	64.65	118.85	118.00	114.03	156.56	122.77	140.57	79.70	77.01	75.76	95.84	92.69	89.76	75.36
	116	111.49	116.25	112.12	110.56	113.69	116.03	110.55	121.06	35.75	60.31	55.44	122.18	122.50	114.99	106.08

OVERFIRE AIR OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST		16	17	18	19	20	21	22	23	24
T/C #	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	3	0.0	61.37	0.0	60.27	72.09	0.0	0.0	0.0	10.69
	4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	5	64.11	97.15	65.32	109.56	97.65	41.54	65.40	55.97	78.34
	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	7	78.70	107.38	86.30	138.79	124.14	58.80	83.64	73.27	96.59
	8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	9	19.89	22.03	17.49	30.48	25.93	98.26	15.08	112.82	27.85
	10	20.79	42.26	23.75	70.47	43.12	71.80	32.97	86.35	45.90
	11	88.92	45.90	41.82	43.16	44.94	11.32	40.21	25.55	53.16
	12	92.57	65.53	84.21	63.24	65.87	38.16	62.92	52.65	75.92
	13	77.05	63.37	30.08	51.34	60.40	75.45	29.37	90.00	42.28
	14	77.05	67.02	79.17	86.90	55.85	0.0	0.0	0.0	0.0
	15	43.27	14.43	49.00	13.40	17.79	3.66	3.91	17.58	14.55
	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	17	0.0	151.51	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	18	46.00	101.62	44.46	159.88	99.55	39.04	101.22	53.60	114.29
	19	79.71	100.15	82.73	154.40	134.26	90.94	108.53	105.55	121.59
	20	85.18	100.15	132.82	91.25	107.77	106.46	84.79	121.08	97.86
	21	97.97	53.45	70.44	71.39	54.85	70.87	79.32	85.47	92.38
	22	0.0	154.45	0.0	0.0	106.30	16.68	224.50	31.09	237.56
	23	145.51	142.04	179.56	138.01	105.99	122.06	151.54	136.72	164.63
	24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	26	129.93	84.32	119.30	190.94	129.74	130.29	85.79	144.94	98.88
	27	105.59	95.23	130.50	177.26	173.56	160.42	0.0	175.06	0.0
	28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	29	152.60	150.77	159.27	53.37	87.51	115.48	116.65	130.16	129.77
	30	151.69	176.33	171.13	160.09	115.82	145.62	151.35	160.29	164.46
	31	0.0	222.25	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	32	62.21	84.29	54.31	74.78	71.08	143.80	67.37	158.47	80.47
	33	72.24	60.44	52.49	150.97	70.17	158.41	116.65	175.07	129.77
	34	72.24	152.23	57.05	153.32	125.87	39.85	129.44	54.46	142.55
	35	72.24	50.94	83.03	148.75	114.00	33.52	98.39	43.10	111.50
	36	152.82	47.00	154.10	163.67	52.26	143.24	67.73	157.95	80.87
	37	172.08	122.03	174.17	54.13	96.95	79.32	29.64	94.03	42.68
	38	164.49	135.20	114.62	146.32	79.60	26.67	41.38	41.25	54.47
	39	140.13	145.40	155.92	40.86	125.27	124.06	27.64	138.78	40.87
	40	93.55	122.03	84.59	160.41	120.70	129.54	118.84	144.25	131.99
	41	90.81	101.53	91.00	169.15	105.08	130.45	116.10	145.17	129.25
	42	179.38	124.42	172.35	154.54	135.31	0.0	0.0	0.0	0.0
	43	194.28	215.24	189.49	175.85	149.32	129.90	115.55	144.66	128.74
	44	225.26	186.03	221.38	165.88	132.88	128.98	73.57	143.74	86.75
	45	193.37	91.12	201.84	152.12	86.23	125.33	94.55	140.09	107.74

OVERFIRE AIR OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST		16	17	18	19	20	21	22	23	24
T/C *	46	168.74	147.38	161.71	141.16	111.87	79.68	78.13	94.43	91.31
	47	186.08	179.51	176.51	156.68	131.06	97.02	95.46	111.78	108.65
	48	197.02	184.62	193.64	158.51	169.40	120.76	111.90	135.52	125.09
	49	176.96	175.13	167.19	138.42	158.45	110.71	101.86	125.48	115.04
	50	168.41	181.73	155.89	140.83	181.84	94.91	53.27	109.72	66.48
	51	161.11	67.07	166.85	140.83	96.92	91.26	45.10	106.07	58.29
	52	188.48	162.75	182.36	109.77	177.27	97.65	46.01	112.46	59.20
	53	120.02	35.08	113.88	110.69	45.88	60.26	54.18	75.05	67.39
	54	133.72	47.41	129.41	152.70	46.78	74.84	95.19	89.64	108.43
	55	146.50	154.72	118.45	137.17	138.03	73.93	44.20	88.73	57.38
	56	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	57	78.70	98.61	74.44	107.73	105.87	75.20	73.60	89.69	66.55
	58	88.74	118.34	86.30	124.17	138.75	68.82	84.55	83.30	97.50
	59	63.20	80.35	60.76	83.07	97.65	43.35	52.66	57.79	65.58
	60	102.62	37.19	96.51	34.10	36.77	22.85	20.41	37.25	33.24
	61	30.67	40.09	30.06	43.16	37.68	15.72	30.27	30.03	43.18
	62	0.0	56.31	0.0	0.0	54.94	0.0	108.54	0.0	121.56
	63	120.89	59.73	104.73	96.03	59.49	113.79	71.12	128.35	84.12
	64	98.05	134.95	81.90	75.94	165.39	90.96	62.01	105.52	75.01
	65	50.54	29.51	50.82	27.70	27.65	22.83	13.32	37.29	26.11
	66	128.11	45.45	111.95	55.61	53.03	23.73	40.20	38.19	53.21
	67	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	68	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	69	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	70	162.86	119.39	149.44	63.14	117.87	0.0	0.0	0.0	0.0
	71	98.93	48.59	127.52	46.75	157.13	36.41	30.35	50.99	43.35
	72	173.81	120.63	256.77	80.47	141.61	66.39	63.91	81.03	76.99
	73	194.73	104.04	242.41	86.86	114.21	166.81	75.76	181.45	88.85
	74	166.50	55.87	179.56	82.30	144.35	127.55	86.70	142.20	99.80
	75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	76	190.01	63.63	138.46	146.93	96.64	137.40	144.96	152.06	158.07
	77	74.07	112.73	74.34	62.93	102.12	51.64	44.64	66.28	57.71
	78	199.13	128.13	199.60	64.75	113.08	46.19	47.36	60.82	60.44
	79	93.24	52.93	95.34	79.34	57.41	20.05	77.40	34.55	90.51
	80	264.96	57.06	278.86	260.23	64.10	197.99	130.71	212.68	143.86
	81	293.11	97.93	292.47	242.04	191.90	214.40	54.99	229.08	68.12
	82	129.17	95.01	131.27	209.27	134.40	144.15	145.33	158.86	158.47
	83	220.39	102.31	226.12	56.95	103.34	127.71	78.67	142.45	91.82
	84	182.11	127.16	191.50	130.80	130.75	0.0	0.0	0.0	0.0
	85	191.55	63.39	212.77	163.07	59.85	150.90	133.82	165.65	147.01
	86	177.37	154.69	196.29	191.35	110.96	134.46	142.95	149.22	156.14
	87	112.13	167.53	110.57	207.75	138.56	150.90	146.60	165.65	159.79
	88	196.11	163.45	170.70	179.50	163.01	118.94	102.77	133.70	115.96
	89	191.55	155.42	166.34	153.51	177.61	88.80	77.21	103.56	90.40
	90	42.50	53.95	42.75	155.44	57.70	94.00	71.47	108.81	84.70

OVERFIRE AIR OPERATION STUDY

WATERWALL ABSORPTION RATES, kW/m^2

TEST	16	17	18	19	20	21	22	23	24
T/C # 91	196.69	182.40	197.86	136.46	157.20	115.00	128.07	129.81	141.30
92	162.02	166.40	173.23	186.46	144.42	113.17	118.02	127.99	131.26
93	198.51	212.09	190.03	191.93	162.68	125.05	144.51	139.86	157.74
94	170.24	77.28	185.09	171.87	153.55	98.57	112.54	113.38	125.78
95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
96	46.99	71.40	40.36	66.82	88.68	166.75	100.32	181.30	113.34
97	167.37	81.90	161.27	139.74	83.12	148.47	106.70	163.08	119.77
98	170.16	155.92	211.46	141.66	157.13	0.0	0.0	0.0	0.0
99	158.99	204.78	196.67	109.48	180.64	61.65	73.75	76.30	86.86
100	242.24	126.43	207.00	190.13	117.04	152.37	81.41	167.08	94.56
101	184.25	161.26	194.55	183.14	179.44	115.28	58.08	130.04	71.25
102	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
103	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
104	147.05	103.37	136.40	175.63	189.29	53.47	59.93	63.66	69.04
105	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
106	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
107	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
108	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
109	52.27	84.73	48.02	80.34	79.39	35.20	51.75	49.62	64.67
110	112.07	78.03	101.29	125.26	63.61	100.09	68.39	114.65	81.39
111	44.18	100.15	45.37	120.61	109.60	44.48	95.75	59.05	108.81
112	199.24	109.83	174.39	116.09	116.04	0.0	0.0	0.0	0.0
113	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
114	192.13	186.31	211.55	70.53	194.63	135.02	57.72	143.73	70.65
115	177.67	100.62	174.05	125.63	89.04	109.80	39.93	124.56	53.06
116	141.94	116.73	132.15	131.69	117.93	84.87	89.72	99.68	102.95

BASELINE OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8	9	10
	Date	1976	3/10	3/08	3/15	3/13	5/23	5/23	5/23	3/10	3/09	3/10
	Time		09:45	14:00	15:35	10:00	12:35	14:30	16:20	14:00	10:00	16:30
*C	Load	MW	524	524	483	399	324	323	322	514	515	482
	FLOWS - 10^3LB/HR											
C	Feedwater		3170	3338	2996	2412	1974	1987	1967	3085	3134	2866
C	Superheat Spray L		107	24	74	6	0	0	3	104	94	76
C	Superheat Spray R		130	64	80	68	35	34	42	131	110	107
C	Reheat Spray L		57	39	50	10	0	0	0	69	60	39
C	Reheat Spray R		75	60	59	0	0	0	0	81	77	59
C	BFP Turb. Extr. Stm. Flow 1-A		0	0	0	0	44	44	44	0	0	0
C	BFP Turb. Extr. Stm. Flow 1-B		0	0	0	0	34	34	34	0	0	0
C	BFP Turb. Mn. Stm. Flow Combined		7.4	7.8	7.0	7.4	15.0	15.1	14.9	7.5	7.3	6.3
C	Hot Air to Burners L Windbox		1626	1606	1612	1298	864	950	1017	1548	1630	1555
C	Hot Air to Burners R Windbox		1585	1560	1593	1284	919	1023	1088	1506	1581	1516
	PRESSURES											
	Steam & Water - PSIG											
C	Feedwater to Econ.		2735	2751	2698	2620	2566	2568	2573	2722	2734	2636
C	Boiler Drum		2682	2691	2654	2586	2538	2541	2544	2668	2679	2637
C	Turbine Throttle		2399	2400	2406	2399	2406	2405	2403	2400	2403	1446
C	Turbine 1st Stage		1666	1682	1520	1242	987	987	985	1618	1634	1501
C	HP Htr. 1-G1 & 1-G2 Steam In.		539	536	492	391	310	310	309	527	529	488
	Air & Gas - IN H_2O											
C	FD Fan 1-A Discharge		5.67	5.63	5.87	4.35	8.70	9.35	9.77	5.43	5.82	5.47
C	FD Fan 1-B Discharge		9.13	8.68	9.61	6.79	7.76	8.23	8.59	8.59	9.41	8.66
C	Air Htr. 1-A Air In.		7.72	7.50	8.21	5.84	7.29	7.73	7.98	7.18	8.01	7.30
C	Air Htr. 1-B Air In.		7.24	6.86	7.61	5.46	6.74	7.08	7.32	6.74	7.43	6.80
C	Air Htr. 1-A Air Out.		3.68	3.51	3.93	3.04	5.66	5.67	5.85	3.49	3.74	3.54
C	Air Htr. 1-B Air Out.		3.50	3.50	3.93	2.95	5.56	5.51	5.71	3.34	3.83	3.38
C	Furn. Right Windbox		2.22	2.12	2.49	2.28	4.97	5.04	5.04	2.16	2.41	2.22
C	Furn. Left Windbox		2.25	2.20	2.47	2.34	4.97	5.07	5.04	2.20	2.38	2.28
C	Rt. WDBX to Furn. Diff. P		3.22	3.18	3.65	3.16	6.19	6.21	6.20	3.17	3.40	3.14
C	Left WDBX to Furn. Diff. P		4.03	3.90	4.13	3.82	6.68	6.79	6.72	3.93	3.98	3.89
C	Furnace		-.51	-.50	-.60	-.39	-.66	-.54	-.57	-.47	-.48	-.44
C	Pri. SH Gas Out.		-.83	-.73	-.64	-.53	-.51	-.50	-.53	-.67	-.72	-.79
C	Reheater Gas Out.		-.66	-.61	-.56	-.19	-.78	-.77	-.84	-.00	-.56	-.62
C	Econ. Gas In.		-2.58	-2.34	-2.49	-1.79	-1.20	-1.29	-1.35	-2.54	-2.45	-2.54
C	Econ. Gas Out.		-6.46	-6.34	-6.42	-4.49	-2.70	-3.00	-3.15	-6.04	-6.39	-6.00
C	Air Htr. 1-A Gas In.		-8.62	-8.25	-8.87	-6.36	-3.99	-4.12	-4.54	-8.15	-8.89	-8.00
C	Air Htr. 1-B Gas In.		-8.56	-8.43	-8.65	-6.24	-4.13	-4.25	-4.63	-8.12	-8.37	-8.00
C	Air Htr. 1-A Gas Out.		-15.5	-15.3	-15.6	-11.2	-6.76	-7.30	-7.94	-14.7	-15.4	-14.6
C	Air Htr. 1-B Gas Out.		-14.2	-14.0	-14.6	-10.2	-6.41	-6.98	-7.34	-13.1	-14.1	-13.3
C	IDF 1-A Disch.		-.51	-.55	-.48	-1.07	-.77	-.66	-.60	-.51	-.52	-.54
C	IDF 1-B Disch.		-.46	-.48	-.47	-2.15	-.88	-.76	-.69	-.50	-.45	-.49
C	PAF 1-A Disch. Hdr.		32.92	32.87	32.64	32.47	31.56	31.54	31.64	32.76	32.74	32.89
C	PAF 1-B Disch. Hdr.		32.67	32.77	32.52	32.29	32.28	32.23	32.30	32.56	32.64	32.55
*B	Pri. Hot Air Duct		30	30	30	30	30	30	30	30	30	30
	TEMPERATURES											
	Air & Gas - °F											
C	1-A FD Fan Disch.		51	41	46	41	77	77	76	55	46	52
C	1-B FD Fan Disch.		60	52	57	50	83	84	85	65	58	61
C	1-A AH Air In.		77	83	82	107	102	104	103	75	76	77
C	1-B AH Air In.		78	88	87	112	105	107	105	78	80	80
C	1-A AH Air Out.		696	668	684	627	565	573	576	698	689	693
C	1-B AH Air Out.		712	686	702	630	576	584	589	718	703	712
C	1-A AH Gas In.		760	730	750	682	612	622	624	763	753	757
C	1-B AH Gas In.		759	732	751	676	608	616	620	763	753	759
C	1-A AH Gas Out.		272	258	265	253	241	243	243	274	265	270
C	1-B AH Gas Out.		272	265	267	246	242	240	239	275	274	270

* C - Computer Data; B - Board Data; NA - Not Available.

BASELINE OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		11	12	13	14	15	16	17	18	19
	Date	1976	5/21	5/25	3/12	3/9	3/10	3/13	5/25	5/25	5/25
	Time		05:00	13:00	06:00	14:00	18:50	13:30	18:20	16:30	14:35
*C	Load	MW	321	321	525	512	484	400	322	325	322
	FLOWS - 10^3LB/HR										
C	Feedwater		1734	1824	3115	3179	2859	2444	1820	1818	1810
C	Superheat Spray L		91	55	113	61	102	0	56	65	66
C	Superheat Spray R		117	74	120	79	106	54	82	96	84
C	Reheat Spray L		14	0	81	58	44	10	10	8	4
C	Reheat Spray R		30	15	83	76	67	0	29	27	23
C	BFP Turb. Extr. Stm. Flow 1-A		39	39	0	0	0	0	44	42	39
C	BFP Turb. Extr. Stm. Flow 1-B		70	71	0	0	0	0	34	52	71
C	BFP Turb. Mn. Stm. Flow Combined		7.6	8.3	7.6	7.6	6.8	7.6	14.1	11.2	8.3
C	Hot Air to Burners L Windbox		790	1190	1567	1622	1602	1302	896	1046	1210
C	Hot Air to Burners R Windbox		810	1241	1504	1575	1558	1283	900	1099	1259
	PRESSURES										
	Steam & Water - PSIG										
C	Feedwater to Econ.		2547	2556	2726	2683	2686	2625	2559	2558	2558
C	Boiler Drum		2521	2529	2675	2676	2639	2589	2532	2531	2532
C	Turbine Throttle		2403	2405	2397	2402	2397	2404	2408	2407	2403
C	Turbine 1st Stage		966	969	1649	1623	1503	1245	958	969	968
C	HP Htr. 1-G1 & 1-G2 Steam In.		313	311	539	526	490	393	312	316	313
	Air & Gas - IN H_2O										
C	FD Fan 1-A Discharge		6.45	11.58	5.29	5.79	5.60	4.25	8.64	10.46	11.89
C	FD Fan 1-B Discharge		5.71	10.01	8.69	9.24	9.00	6.71	7.85	9.32	10.21
C	Air Htr. 1-A Air In.		5.36	9.08	7.28	7.96	7.47	5.84	7.30	8.54	9.17
C	Air Htr. 1-B Air In.		4.88	8.25	6.71	7.41	6.96	5.33	6.64	7.85	8.41
C	Air Htr. 1-A Air Out.		4.04	6.43	3.38	3.82	3.57	2.93	5.57	6.31	6.47
C	Air Htr. 1-B Air Out.		3.65	6.31	3.43	3.80	3.45	2.87	5.51	6.22	6.42
C	Furn. Right Windbox		3.62	5.40	2.10	2.32	2.20	2.30	5.00	5.47	5.37
C	Furn. Left Windbox		3.57	6.12	2.11	2.35	2.21	2.37	4.94	5.49	5.45
C	Rt. WDBX to Furn. Diff. P		4.21	6.54	3.13	3.23	3.17	3.16	5.79	6.56	6.58
C	Left WDBX to Furn. Diff. P		5.17	6.96	3.92	3.94	3.93	3.88	6.46	7.03	7.00
C	Furnace		-.42	-.61	-.41	-.68	-.53	-.40	-.55	-.61	-.61
C	Pri. SH Gas Out.		-.55	-.58	-.82	-.77	-.61	-.54	-.62	-.63	-.69
C	Reheater Gas Out.		-.73	-.94	-.84	-.70	-.47	-.29	-.90	-.93	-1.02
C	Econ. Gas In.		-1.29	-1.52	-2.43	-2.42	-2.58	-1.75	-1.23	-1.36	-1.54
C	Econ. Gas Out.		-2.48	-3.72	-6.39	-6.49	-6.12	-4.39	-2.65	-3.23	-3.83
C	Air Htr. 1-A Gas In.		-3.52	-5.11	-8.74	-8.75	-8.24	-6.41	-3.84	-4.69	-5.30
C	Air Htr. 1-B Gas In.		-3.74	-5.20	-8.09	-8.34	-8.18	-6.18	-3.90	-4.75	-5.50
C	Air Htr. 1-A Gas Out.		-6.29	-9.15	-15.0	-15.4	-14.9	-11.3	-6.74	-8.13	-9.50
C	Air Htr. 1-B Gas Out.		-5.90	-8.52	-13.5	-14.3	-13.6	-10.3	-6.23	-7.35	-8.72
C	IDF 1-A Disch.		-.94	-.39	-.49	-.43	-.49	-.94	-.62	-.45	-.32
C	IDF 1-B Disch.		-.91	-.45	-.41	-.69	-.43	-.93	-.62	-.44	-.38
C	PAF 1-A Disch. Hdr.		31.66	31.66	32.85	32.64	32.81	32.69	31.63	31.74	31.76
C	PAF 1-B Disch. Hdr.		32.72	32.52	32.77	32.44	32.63	32.29	32.53	32.77	32.64
*B	Pri. Hot Air Duct		30	30	30	30	30	30	30	30	30
	TEMPERATURES										
	Air & Gas - °F										
C	1-A FD Fan Disch.		72	77	56	50	49	46	81	80	79
C	1-B FD Fan Disch.		83	82	68	58	58	55	92	89	85
C	1-A AH Air In.		96	99	71	70	78	102	100	98	101
C	1-B AH Air In.		100	102	74	73	82	107	102	100	105
C	1-A AH Air Out.		590	604	710	705	688	631	591	603	607
C	1-B AH Air Out.		608	627	724	725	710	634	612	620	629
C	1-A AH Gas In.		641	655	774	771	753	685	637	652	600
C	1-B AH Gas In.		637	657	776	775	757	680	640	653	661
C	1-A AH Gas Out.		247	244	276	270	267	253	244	245	245
C	1-B AH Gas Out.		259	241	276	278	268	249	252	245	243

* C - Computer Data; B - Board Data; NA - Not Available.

BASELINE OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8	9	10
	Date	1976	3/10	3/08	3/15	3/13	5/23	5/23	5/23	3/10	3/09	3/10
	Time		09:45	14:00	15:35	10:00	12:35	14:30	16:20	14:00	10:00	16:30
*C	Load	MW	524	524	483	399	324	323	322	514	515	482
	TEMPERATURES											
	Air & Gas - °F											
C	Econ. N Gas Out.		788	750	780	710	638	651	655	794	775	782
C	Econ. S Gas Out.		802	758	792	728	548	557	556	800	791	796
C	1-A PA Fan Disch. Hdr.		60	52	55	53	86	85	84	66	56	62
C	1-B PA Fan Disch. Hdr.		95	95	69	64	*NA	NA	NA	104	106	101
C	1-A AH Pri. Air Out.		708	681	697	639	579	586	588	712	701	707
C	1-B AH Pri. Air Out.		689	669	686	620	574	577	579	694	686	690
	Steam & Water - °F											
C	Boiler Econ. In		480	477	471	448	424	424	424	477	477	468
C	Downcomer 1		677	675	675	673	666	666	666	676	674	674
C	Downcomer 2		678	676	677	674	668	668	668	678	676	676
C	Downcomer 3		679	677	677	674	669	669	669	678	676	676
C	Downcomer 4		682	681	676	676	673	673	673	682	680	680
C	Downcomer 5		680	679	676	676	670	670	670	679	678	677
C	Blr. SH ATMP 1-A Stm. In.		851	830	838	850	844	837	839	860	848	865
C	Blr. SH ATMP 1-B Stm. In.		856	829	846	827	813	813	822	855	848	858
C	Blr. S SH Hdr. Out.		1008	1002	1006	1014	1008	1003	1009	1009	1006	1009
C	Blr. N SH Hdr. Out.		1001	1011	1011	1012	1001	996	1008	999	1003	1003
C	Turbine Throttle		1002	1000	1006	1009	1001	999	1006	1003	1002	1004
C	Blr. S RH ATMP Stm. Out. A		478	480	471	589	550	547	554	478	476	472
C	Blr. N RH ATMP Stm. Out. B		479	480	471	588	550	546	553	479	477	471
C	Blr. S RH Hdr. Out. A		991	989	1000	1019	966	957	952	990	989	1008
C	Blr. N RH Hdr. Out. B		1015	1015	1012	992	963	964	966	1014	1020	1006
C	HP Htr. 1-G1 & 1-G2 Extr. Stm.		618	620	610	581	543	538	547	620	619	607
C	HP Htr. 1-F1 FW Out.		411	407	404	387	366	366	366	410	408	404
C	HP Htr. 1-F2 FW Out.		410	407	403	386	366	365	365	410	407	403
C	HP Htr. 1-G1 FW Out.		479	476	470	449	424	423	423	477	475	469
C	HP Htr. 1-G2 FW Out.		479	476	469	449	424	423	423	477	475	469
C	HP Htr. 1-G1 Drain		415	412	406	387	366	366	366	415	411	406
C	HP Htr. 1-G2 Drain		382	377	374	357	335	335	335	381	376	376
	PULVERIZER DATA											
C	PLV 1-A Bowl Lower P	IN. H_2O	21.36	21.52	20.23	18.51	-.27	-.28	-.15	20.90	21.39	20.25
C	PLV 1-B Bowl Lower P	IN. H_2O	22.68	22.37	21.29	19.49	-1.18	-1.17	-1.10	22.38	22.51	21.69
C	PLV 1-C Bowl Lower P	IN. H_2O	.23	.13	.21	.19	19.31	19.16	19.21	.25	.23	.25
C	PLV 1-D Bowl Lower P	IN. H_2O	22.89	23.09	22.04	19.64	19.36	19.34	19.38	22.54	22.87	21.78
C	PLV 1-E Bowl Lower P	IN. H_2O	22.16	22.19	21.44	19.84	19.74	19.39	19.58	21.89	22.25	21.24
C	PLV 1-F Bowl Lower P	IN. H_2O	22.81	21.51	19.83	17.78	18.15	18.06	18.52	20.28	21.10	19.39
C	PLV 1-A Bowl Diff. P	IN. H_2O	7.61	7.67	7.14	6.66	.45	.45	.45	7.53	7.67	7.12
C	PLV 1-B Bowl Diff. P	IN. H_2O	7.80	7.74	7.41	6.79	.20	.20	.20	7.74	7.77	7.47
C	PLV 1-C Bowl Diff. P	IN. H_2O	.06	.00	.03	.02	6.39	6.41	6.38	.06	.05	.07
C	PLV 1-D Bowl Diff. P	IN. H_2O	7.95	8.00	7.72	6.82	6.46	6.44	6.46	7.66	7.98	7.58
C	PLV 1-E Bowl Diff. P	IN. H_2O	7.12	7.10	6.99	6.46	6.18	6.20	6.14	7.02	7.13	6.88
C	PLV 1-F Bowl Diff. P	IN. H_2O	7.17	7.32	6.93	6.21	6.05	6.13	6.21	7.08	7.21	6.83
C	PLV 1-A Coal Air Out. P	IN. H_2O	9.84	10.17	9.41	8.43	-1.11	-.96	-.95	9.68	10.06	9.32
C	PLV 1-B Coal Air Out. P	IN. H_2O	11.36	11.15	10.71	9.74	-1.23	-1.15	-1.16	11.24	11.37	10.89
C	PLV 1-C Coal Air Out. P	IN. H_2O	-.13	-.35	-.19	-.22	9.32	9.35	9.25	-.13	-.23	-.14
C	PLV 1-D Coal Air Out. P	IN. H_2O	10.80	10.99	10.45	9.34	9.23	9.33	9.19	10.61	10.85	10.78
C	PLV 1-E Coal Air Out. P	IN. H_2O	11.58	11.56	11.17	10.26	9.64	9.89	9.63	11.29	11.66	10.03
C	PLV 1-F Coal Air Out. P	IN. H_2O	10.26	10.67	9.55	8.58	8.83	9.03	8.93	9.88	10.41	9.44
C	PLV 1-A Pri. Air In. Flow	0-125%	126.1	125.1	125.8	125.7	0.0	0.0	0.0	125.9	125.6	125.3
C	PLV 1-B Pri. Air In. Flow	0-125%	127.8	128.3	128.6	128.4	30.8	30.2	29.7	128.4	128.6	128.4
C	PLV 1-C Pri. Air In. Flow	0-125%	37.2	0.0	0.0	0.0	131.2	131.4	131.4	45.9	46.9	47.3
C	PLV 1-D Pri. Air In. Flow	0-125%	125.2	125.4	126.0	125.6	126.2	125.9	126.3	124.9	125.3	124.8
C	PLV 1-E Pri. Air In. Flow	0-125%	127.8	127.7	127.9	128.5	126.3	129.2	129.4	127.9	127.9	127.9
C	PLV 1-F Pri. Air In. Flow	0-125%	125.2	125.1	125.0	125.3	126.2	125.3	124.0	124.5	124.7	125.4
C	PLV 1-A Coal Air Disch. Temp.	°F	144	139	142	144	87	88	88	142	141	143

* C - Computer Data; B - Board Data; NA - Not Available.

BASELINE OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		11	12	13	14	15	16	17	18	19
	Date	1976	5/21	5/25	3/12	3/9	3/10	3/13	5/25	5/25	5/25
	Time		05:00	13:00	06:00	14:00	18:50	13:30	18:20	16:30	14:35
*C	Load	MW	321	321	525	512	484	400	322	325	322
	TEMPERATURES										
	Air & Gas - °F										
C	Econ. N Gas Out.		662	693	817	794	780	707	663	687	702
C	Econ. S Gas Out.		648	479	817	806	788	726	416	448	461
C	1-A PA Fan Disch. Hdr.		78	88	66	59	58	58	90	90	90
C	1-B PA Fan Disch. Hdr.		*NA	NA	104	106	93	75	NA	NA	NA
C	1-A AH Pri. Air Out.		605	616	723	718	702	645	602	614	619
C	1-B AH Pri. Air Out.		604	610	710	706	688	624	604	610	612
	Steam & Water - °F										
C	Boiler Econ. In.		425	424	478	476	469	448	424	426	425
C	Downcomer 1		666	666	676	674	674	673	666	666	664
C	Downcomer 2		667	668	678	676	676	674	668	668	668
C	Downcomer 3		668	668	678	679	676	674	668	668	668
C	Downcomer 4		667	672	682	680	680	679	673	673	673
C	Downcomer 5		667	670	680	678	678	676	670	669	670
C	Blr. SH ATMP 1-A Stm. In.		917	882	860	841	864	842	892	904	891
C	Blr. SH ATMP 1-B Stm. In.		878	862	862	842	853	847	857	865	871
C	Blr. S SH Hdr. Out.		1011	1005	1013	1007	1011	1010	1010	1010	1006
C	Blr. N SH Hdr. Out.		997	1005	1010	1005	1002	1012	998	1000	1003
C	Turbine Throttle		1003	1003	1007	1004	1005	1008	1003	1002	1003
C	Blr. S RH ATMP Stm. Out. A		427	454	479	476	472	588	427	427	428
C	Blr. N RH ATMP Stm. Out. B		425	429	482	477	470	587	425	426	427
C	Blr. S RH Hdr. Out. A		1005	970	1019	990	1006	1015	974	976	972
C	Blr. N RH Hdr. Out. B		994	986	1012	1015	1007	994	975	982	984
C	HP Htr. 1-G1 & 1-G2 Extr. Stm.		548	544	628	619	608	580	546	546	545
C	HP Htr. 1-F1 FW Out.		368	366	412	409	404	387	367	368	367
C	HP Htr. 1-F2 FW Out.		369	366	412	408	403	386	366	367	366
C	HP Htr. 1-G1 FW Out.		424	424	479	476	469	449	424	424	424
C	HP Htr. 1-G2 FW Out.		424	424	479	477	469	449	424	425	424
C	HP Htr. 1-G1 Drain		367	366	415	413	406	387	366	367	366
C	HP Htr. 1-G2 Drain		338	337	379	380	373	357	337	338	337
	PULVERIZER DATA										
C	PLV 1-A Bowl Lower P	IN. H_2O	18.56	18.42	21.65	20.97	20.25	18.64	18.21	18.43	18.39
C	PLV 1-B Bowl Lower P	IN. H_2O	21.00	20.41	23.23	22.35	21.56	19.17	20.33	20.93	20.78
C	PLV 1-C Bowl Lower P	IN. H_2O	19.96	19.60	.24	.24	.23	.19	19.18	12.62	19.52
C	PLV 1-D Bowl Lower P	IN. H_2O	19.53	19.45	23.44	22.50	21.84	19.78	19.44	19.56	19.44
C	PLV 1-E Bowl Lower P	IN. H_2O	-.89	0.0	21.88	21.89	21.30	19.91	-.01	0.0	0.0
C	PLV 1-F Bowl Lower P	IN. H_2O	-1.16	-1.10	18.87	20.47	19.48	17.68	-1.22	-1.24	-1.23
C	PLV 1-A Bowl Diff. P	IN. H_2O	6.37	6.36	7.75	7.60	7.25	6.65	6.32	6.34	6.39
C	PLV 1-B Bowl Diff. P	IN. H_2O	6.53	6.57	8.12	7.73	7.44	6.72	6.58	6.79	6.73
C	PLV 1-C Bowl Diff. P	IN. H_2O	6.68	6.46	.06	.07	.07	.25	6.32	6.56	6.47
C	PLV 1-D Bowl Diff. P	IN. H_2O	6.69	6.54	8.21	7.77	7.56	6.82	6.48	6.55	6.55
C	PLV 1-E Bowl Diff. P	IN. H_2O	.12	.01	7.15	7.04	6.91	6.42	.02	.02	.03
C	PLV 1-F Bowl Diff. P	IN. H_2O	.06	.06	6.65	7.07	6.82	6.12	.06	.06	.06
C	PLV 1-A Coal Air Out. P	IN. H_2O	8.21	8.23	9.80	9.90	9.21	8.45	8.07	7.95	8.15
C	PLV 1-B Coal Air Out. P	IN. H_2O	10.04	10.28	11.55	11.16	10.73	9.56	10.37	10.49	10.43
C	PLV 1-C Coal Air Out. P	IN. H_2O	9.66	9.42	-.13	-.17	-.14	-.23	9.12	9.37	9.41
C	PLV 1-D Coal Air Out. P	IN. H_2O	9.14	9.18	10.96	10.64	10.22	9.42	9.17	9.11	9.26
C	PLV 1-E Coal Air Out. P	IN. H_2O	1.13	.05	11.15	11.24	10.94	10.28	.05	.06	.05
C	PLV 1-F Coal Air Out. P	IN. H_2O	1.37	-1.26	9.04	10.15	9.34	8.54	-1.47	-1.26	-1.19
C	PLV 1-A Pri. Air In. Flow	0-125%	126.8	126.8	125.6	125.4	126.2	125.8	127.1	127.3	126.1
C	PLV 1-B Pri. Air In. Flow	0-125%	128.8	129.3	128.5	128.7	128.4	128.5	128.9	129.3	129.6
C	PLV 1-C Pri. Air In. Flow	0-125%	130.8	131.2	33.1	59.5	42.4	0.0	130.0	131.7	131.0
C	PLV 1-D Pri. Air In. Flow	0-125%	126.0	125.6	125.2	125.2	125.4	125.6	125.4	125.6	125.8
C	PLV 1-E Pri. Air In. Flow	0-125%	0.0	0.0	127.5	128.0	127.8	127.8	0.0	0.0	0.0
C	PLV 1-F Pri. Air In. Flow	0-125%	0.0	0.0	125.6	124.8	124.7	124.7	0.0	0.0	0.0
C	PLV 1-A Coal Air Disch. Temp.	°F	144	143	143	141	143	144	142	142	142

* C - Computer Data; B - Board Data; NA - Not Available.

BASELINE OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8	9	10
	DATE	1976	3/10	3/08	3/15	3/13	5/23	5/23	5/23	3/10	3/09	3/10
	TIME		09:45	14:00	15:35	10:00	12:35	14:30	16:20	14:00	10:00	16:30
*C	LOAD	MW	524	524	483	399	324	323	322	514	515	482
	PULVERIZER DATA											
C	PLV 1-B COAL AIR DISCH. TEMP.	°F	146	142	145	146	121	114	110	145	143	146
C	PLV 1-C COAL AIR DISCH. TEMP.	°F	55	79	89	43	144	144	144	57	69	55
C	PLV 1-D COAL AIR DISCH. TEMP.	°F	147	144	146	146	141	144	142	147	146	146
C	PLV 1-E COAL AIR DISCH. TEMP.	°F	141	138	141	143	138	138	138	141	139	142
C	PLV 1-F COAL AIR DISCH. TEMP	°F	145	141	144	145	141	142	142	144	142	144
C	PLV 1-A FEEDER COAL FLOW	10^3 LB/HR	116	116	105	87	0	0	0	114	114	106
C	PLV 1-B FEEDER COAL FLOW	10^3 LB/HR	117	112	106	88	0	0	0	115	111	107
C	PLV 1-C FEEDER COAL FLOW	10^3 LB/HR	0	0	0	0	87	87	87	0	0	0
C	PLV 1-D FEEDER COAL FLOW	10^3 LB/HR	114	113	105	87	88	88	89	112	112	104
C	PLV 1-E FEEDER COAL FLOW	10^3 LB/HR	116	115	106	88	88	88	88	114	114	106
C	PLV 1-F FEEDER COAL FLOW	10^3 LB/HR	116	116	104	86	86	86	87	113	115	105
C	PLV 1-A MILL	AMPS	73	74	70	64	0	0	0	73	74	70
C	PLV 1-B MILL	AMPS	72	71	70	65	0	0	0	71	70	70
C	PLV 1-C MILL	AMPS	0	0	0	0	65	67	66	0	0	0
C	PLV 1-D MILL	AMPS	74	73	71	66	65	65	65	73	75	70
C	PLV 1-E MILL	AMPS	75	76	72	65	67	67	66	75	75	73
C	PLV 1-F MILL	AMPS	75	74	71	65	65	66	65	74	75	71
	FAN DAMPER POSITION - % OPEN											
*B	1-A FD FAN INLET VANE		72	70	73	63	58	62	64	70	73	70
B	1-B FD FAN INLET VANE		71	70	71	62	57	60	62	69	71	70
B	1-A PA FAN INLET VANE		30	29	28	28	32	32	32	30	30	30
B	1-B PA FAN INLET VANE		25	24	24	23	26	26	26	25	25	25
	SPRAY VALVE POSITION - % OPEN											
B	1-A SH SPRAY VALVE		100	25	36	23	11	8	10	100	45	85
B	1-B SH SPRAY VALVE		92	13	24	17	6	5	20	100	32	68
B	1-A RH SPRAY VALVE		47	32	41	0	0	0	0	84	50	31
B	1-B RH SPRAY VALVE		65	43	41	0	0	0	0	61	70	41
	MISCELLANEOUS											
B	BURNER TILT	± DEGREES	-3°	0°	-3°	+15°	+6°	+6°	+6°	-3°	0°	-3°
B	AUX. AIR DAMPERS	% OPEN	100	98	100	56	13	21	25	79	100	84
B	1-A FUEL/AIR DAMPERS	% OPEN	51	50	45	31	0	0	0	50	50	45
B	1-B FUEL/AIR DAMPERS	% OPEN	52	49	45	34	0	0	0	50	49	46
B	1-C FUEL/AIR DAMPERS	% OPEN	0	2	0	0	87	88	90	0	0	0
B	1-D FUEL/AIR DAMPERS	% OPEN	51	52	46	35	84	85	83	50	50	46
B	1-E FUEL/AIR DAMPERS	% OPEN	51	52	45	34	80	82	84	50	50	46
B	1-F FUEL/AIR DAMPERS	% OPEN	51	52	45	33	76	78	80	50	50	46
B	1-A PRI. AIR FAN	AMPS	170	175	171	173	165	168	168	171	173	170
B	1-B PRI. AIR FAN	AMPS	180	184	181	185	175	178	178	181	180	180
B	1-A ID FAN	AMPS	500	500	500	380	280	300	310	480	500	470
B	1-B ID FAN	AMPS	430	420	430	320	300	320	320	410	430	400
B	1-A FD FAN	AMPS	201	208	210	187	167	175	179	198	210	200
B	1-B FD FAN	AMPS	198	193	197	177	157	162	166	188	198	190
B	1-A ID FAN	RPM	480	480	480	430	320	340	354	480	480	480
B	1-B ID FAN	RPM	490	490	480	430	315	345	354	488	500	480
B	1-A BLR. CIRC. WTR. PUMP	AMPS	71	73	75	79	83	83	81	74	72	73
B	1-B BLR. CIRC. WTR. PUMP	AMPS	76	76	79	81	95	83	84	77	75	76
B	1-C BLR. CIRC. WTR. PUMP	AMPS	70	72	73	78	80	79	78	72	71	71
B	1-D BLR. CIRC. WTR. PUMP	AMPS	72	73	75	80	85	83	83	74	72	73
C	N DRUM LEVEL ± NORM. H_2O LEVEL	IN.	-.72	-.70	-.57	-.67	-.79	-.63	-.35	-.68	-.78	-.64
C	S DRUM LEVEL ± NORM. H_2O LEVEL	IN.	-3.05	-2.87	-2.01	-1.58	-2.02	-2.26	-1.70	-3.28	-2.92	-2.95
C	FLUE GAS COMBUSTIBLES	%	.062	.064	.067	064	.063	.065	.063	.068	.060	.068
C	FLUE GAS OXYGEN	%	3.8	3.9	4.8	5.3	5.1	5.7	6.0	3.9	4.0	5.0
C	BARONMETRIC PRESS.	IN. HGA	29.76	30.08	30.07	30.08	30.05	30.03	30.02	29.81	29.66	29.87

* C - COMPUTER DATA; B - BOARD DATA; NA - NOT AVAILABLE.

BASELINE OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		11	12	13	14	15	16	17	18	19
	Date	1976	5/21	5/25	3/12	3/9	3/10	3/13	5/25	5/25	5/25
	Time		05:00	13:00	06:00	14:00	18:50	13:30	18:20	16:30	14:35
*C	Load	MW	321	321	525	512	484	400	322	325	322
	PULVERIZER DATA										
C	PLV 1-B Coal Air Disch. Temp.	°F	145	151	145	144	145	146	151	154	153
C	PLV 1-C Coal Air Disch. Temp.	°F	145	144	50	68	53	44	143	144	144
C	PLV 1-D Coal Air Disch. Temp.	°F	143	142	147	146	147	145	142	142	142
C	PLV 1-E Coal Air Disch. Temp.	°F	94	79	141	140	141	142	82	80	80
C	PLV 1-F Coal Air Disch. Temp.	°F	104	134	144	143	144	146	110	114	122
C	PLV 1-A Feeder Coal Flow	10^3 LB/HR	86	88	119	112	107	86	86	88	88
C	PLV 1-B Feeder Coal Flow	10^3 LB/HR	88	90	120	109	109	88	88	90	90
C	PLV 1-C Feeder Coal Flow	10^3 LB/HR	88	89	0	0	0	0	88	90	90
C	PLV 1-D Feeder Coal Flow	10^3 LB/HR	88	90	117	110	105	87	89	91	91
C	PLV 1-E Feeder Coal Flow	10^3 LB/HR	0	0	112	112	107	87	0	0	0
C	PLV 1-F Feeder Coal Flow	10^3 LB/HR	0	0	112	112	106	86	0	0	0
C	PLV 1-A Mill	AMPS	64	64	77	75	69	65	65	65	65
C	PLV 1-B Mill	AMPS	65	65	74	71	70	65	65	65	66
C	PLV 1-C Mill	AMPS	66	67	0	0	0	0	67	67	68
C	PLV 1-D Mill	AMPS	66	66	76	75	70	66	66	66	67
C	PLV 1-E Mill	AMPS	0	0	76	75	73	66	0	0	0
C	PLV 1-F Mill	AMPS	0	0	71	76	71	65	0	0	0
	FAN DAMPER POSITION - % OPEN										
*B	1-A FD Fan Inlet Vane		52	69	71	72	70	64	59	65	69
B	1-B FD Fan Inlet Vane		51	67	70	71	70	63	58	64	68
B	1-A PA Fan Inlet Vane		31	31	30	30	29	29	31	31	31
B	1-B PA Fan Inlet Vane		26	25	25	25	24	24	26	26	26
	SPRAY VALVE POSITION - % OPEN										
B	1-A SH Spray Valve		41	26	52	30	53	22	26	32	32
B	1-B SH Spray Valve		45	25	30	23	41	12	28	41	27
B	1-A RH Spray Valve		19	8	100	49	36	0	17	18	14
B	1-B RH Spray Valve		15	5	100	68	50	0	12	12	9
	MISCELLANEOUS										
B	Burner Tilt	± Degrees	+6°	+3°	-3°	0°	-3°	+17°	+4°	+3°	+4°
B	Aux. Air Dampers	% Open	0	29	95	100	90	57	0	18	31
B	1-A Fuel/Air Dampers	% Open	79	83	54	49	45	31	81	85	85
B	1-B Fuel/Air Dampers	% Open	82	86	54	47	46	33	84	87	87
B	1-C Fuel/Air Dampers	% Open	87	92	0	0	0	0	89	83	93
B	1-D Fuel/Air Dampers	% Open	82	88	54	50	46	35	85	87	89
B	1-E Fuel/Air Dampers	% Open	0	0	50	50	46	33	0	0	0
B	1-F Fuel/Air Dampers	% Open	0	0	44	50	46	32	0	0	0
B	1-A Pri. Air Fan	AMPS	170	165	170	170	170	171	165	165	165
B	1-B Pri. Air Fan	AMPS	178	175	180	180	180	185	175	175	175
B	1-A ID Fan	AMPS	270	340	480	500	480	380	290	310	350
B	1-B ID Fan	AMPS	300	350	410	430	410	320	310	320	340
B	1-A FD Fan	AMPS	158	189	199	205	200	187	165	180	189
B	1-B FD Fan	AMPS	149	175	187	190	190	171	155	165	178
B	1-A ID Fan	RPM	300	393	480	480	480	430	316	360	400
B	1-B ID Fan	RPM	[illegible]	393	480	490	480	430	326	360	400
B	1-A Blr. Circ. Wtr. Pump	AMPS	80	79	73	70	73	79	82	80	79
B	1-B Blr. Circ. Wtr. Pump	AMPS	83	83	76	75	76	81	83	83	80
B	1-C Blr. Circ. Wtr. Pump	AMPS	79	77	72	70	71	76	78	78	76
B	1-D Blr. Circ. Wtr. Pump	AMPS	83	79	74	72	73	80	82	80	78
C	N Drum Level ± Norm. H_2O Level	IN.	-.64	-.56	-.64	-.69	-.65	-.55	-.77	-.67	-.54
C	S Drum Level ± Norm. H_2O Level	IN.	-2.56	-2.13	-1.60	-2.54	-3.03	-1.15	-1.40	-1.79	-2.25
C	Flue Gas Combustibles	%	.063	.067	.065	.064	.066	.065	.066	.068	.066
C	Flue Gas Oxygen	%	4.2	7.0	3.5	4.1	5.0	5.3	4.6	5.9	7.0
C	Baronmetric Press.	IN. HGA	30.08	29.98	29.01	29.56	29.94	30.00	29.91	29.92	29.95

* C - Computer Data; B - Board Data; NA - Not Available.

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8	9
	Date	1976	5/19	5/19	3/12	5/19	5/12	5/12	5/16	5/21	6/27
	Time		16:15	13:50	07:15	11:00	11:00	09:20	09:30	03:10	09:40
*C	Load	MW	505	506	524	506	422	422	421	320	314
	FLOWS - 10^3LB/HR										
C	Feedwater		3176	3200	3111	3111	2666	2634	2624	1727	1979
C	Superheat Spray L		80	66	122	113	0	0	0	90	0
C	Superheat Spray R		83	68	108	95	29	57	22	121	20
C	Reheat Spray L		38	54	91	35	10	9	10	9	0
C	Reheat Spray R		62	74	83	59	6	0	0	24	2
C	BFP Turb. Extr. Stm. Flow 1-A		43	43	0	42	0	0	42	39	34
C	BFP Turb. Extr. Stm. Flow 1-B		68	69	0	69	0	0	72	68	89
C	BFP Turb. Mn. Stm. Flow Combined		8.47	8.49	7.69	8.13	8.80	8.87	8.70	7.12	0.00
C	Hot Air to Burners L Windbox		1481	1382	1516	1384	1247	1169	1285	819	1006
C	Hot Air to Burners R Windbox		1555	1472	1466	1473	1300	1226	1342	826	951
	PRESSURES										
	Steam & Water - PSIG										
C	Feedwater to Econ.		2732	2731	2728	2720	2649	2643	2645	2546	2564
C	Boiler Drum		2674	2678	2676	2670	2607	2604	2605	2519	2531
C	Turbine Throttle		2403	2403	2396	2402	2400	2400	2399	2400	2407
C	Turbine 1st Stage		1618	1620	1649	1623	1319	1322	1321	951	966
C	HP Htr. 1-G1 & 1-G2 Steam In.		519	520	539	518	416	414	415	312	301
	Air & Gas - IN H_2O										
C	FD Fan 1-A Discharge		14.07	13.28	5.36	13.11	11.67	10.86	11.98	5.00	6.96
C	FD Fan 1-B Discharge		13.15	11.98	8.67	11.61	10.05	9.49	10.04	4.39	5.75
C	Air Htr. 1-A Air In.		11.14	10.45	7.32	10.40	9.30	8.71	9.33	3.82	5.30
C	Air Htr. 1-B Air In.		10.26	9.51	6.75	9.43	8.45	7.93	8.56	3.26	4.55
C	Air Htr. 1-A Air Out.		7.02	6.65	3.44	6.61	6.24	6.02	6.35	2.35	3.43
C	Air Htr. 1-B Air Out.		7.02	6.64	3.46	6.74	6.28	6.17	6.22	2.27	3.36
C	Furn. Right Windbox		5.33	5.20	2.39	5.30	5.21	5.23	5.17	1.95	2.94
C	Furn. Left Windbox		5.46	5.31	2.42	5.41	5.24	5.29	5.21	1.93	2.80
C	Rt. WDBX to Furn. Diff. P		6.50	6.53	3.20	6.53	6.54	6.55	6.54	2.02	2.12
C	Left WDBX to Furn. Diff. P		7.01	6.94	4.00	6.90	7.00	7.01	6.99	3.52	3.58
C	Furnace		-0.26	-0.64	-0.43	-0.70	-0.49	-0.42	-0.52	-0.20	-0.54
C	Pri. SH Gas Out.		-0.43	-0.57	-0.73	-0.47	-0.50	-0.53	-0.56	-0.59	-0.73
C	Reheater Gas Out.		-0.98	-1.13	-0.69	-1.05	-0.87	-0.86	-0.91	-0.81	-0.86
C	Econ. Gas In.		-2.13	-2.16	-2.45	-2.15	-1.71	-1.62	-1.82	-1.32	-1.23
C	Econ. Gas Out.		-5.73	-5.61	-6.18	-5.67	-4.19	-3.84	-4.31	-2.58	-2.68
C	Air Htr. 1-A Gas In.		-7.96	-7.74	-8.49	-7.97	-6.14	-5.81	-5.91	-3.52	-3.83
C	Air Htr. 1-B Gas In.		-7.73	-7.54	-8.10	-7.44	-5.67	-5.42	-6.04	-3.76	-3.96
C	Air Htr. 1-A Gas Out.		-14.1	-13.6	-14.9	-13.5	-10.3	-9.7	-10.5	-6.3	-6.4
C	Air Htr. 1-B Gas Out.		-12.9	-12.4	-13.6	-12.2	-9.3	-9.0	-9.7	-6.0	-6.3
C	IDF 1-A Disch.		-0.09	-0.16	-0.56	-0.21	-0.56	-0.79	-0.35	-0.86	-0.41
C	IDF 1-B Disch.		-0.02	-0.12	-0.47	-0.19	-0.52	-0.74	-0.34	-0.84	-0.40
C	PAF 1-A Disch. Hdr.		32.26	32.44	32.91	32.31	31.89	31.93	31.90	31.59	31.64
C	PAF 1-B Disch. Hdr.		33.43	33.44	32.68	33.23	32.75	32.75	32.87	32.77	32.79
*B	Pri. Hot Air Duct		30	30	30	30	30	30	30	30	30
	TEMPERATURES										
	Air & Gas - °F										
C	1-A FD Fan Disch.		84	81	58	75	70	64	73	75	87
C	1-B FD Fan Disch.		91	88	68	80	79	76	80	87	93
C	1-A AH Air In.		98	97	73	89	96	96	91	92	99
C	1-B AH Air In.		102	101	76	92	67	102	95	95	101
C	1-A AH Air Out.		688	688	720	681	639	629	627	594	549
C	1-B AH Air Out.		722	702	738	692	651	641	648	612	566
C	1-A AH Gas In.		744	744	784	737	695	680	679	642	591
C	1-B AH Gas In.		758	744	789	733	688	371	682	641	599
C	1-A AH Gas Out.		291	290	280	282	249	246	250	252	226
C	1-B AH Gas Out.		293	288	283	280	256	254	251	261	238

* C - Computer Data; B - Board Data; NA - Not Available.

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		10	11	12	13	14	15	16	17	18
	Date	1976	5/23	5/19	5/10	3/16	5/12	3/13	5/16	5/21	5/23
	Time		11:05	18:35	09:50	10:00	13:45	15:30	11:45	01:15	09:10
*C	Load	MW	324	491	497	522	422	400	422	320	323
	FLOWS - 10^3 LB/HR										
C	Feedwater		1940	3005	2972	3139	2660	2458	2634	1720	1909
C	Superheat Spray L		12	107	125	135	0	0	9	92	36
C	Superheat Spray R		46	101	140	111	39	34	32	122	48
C	Reheat Spray L		0	40	66	70	11	10	10	5	0
C	Reheat Spray R		0	64	80	75	8	0	0	22	0
C	BFP Turb. Extr. Stm. Flow 1-A		44	42	0	0	0	0	42	39	44
C	BFP Turb. Extr. Stm. Flow 1-B		34	67	0	0	0	0	73	70	34
C	BFP Turb. Mn. Stm. Flow Combined		14.70	8.08	7.65	7.51	8.93	7.61	8.95	7.53	14.99
C	Hot Air to Burners L Windbox		902	1502	1514	1576	1411	1290	1472	967	993
C	Hot Air to Burners R Windbox		913	1583	1554	1552	1869	1287	1533	979	1027
	PRESSURES										
	Steam & Water - PSIG										
C	Feedwater to Econ.		2565	2711	2701	2734	2648	2623	2647	2544	2563
C	Boiler Drum		2539	2660	2652	2687	2608	2587	2608	2520	2540
C	Turbine Throttle		2402	2400	2400	2395	2408	2402	2406	2405	2405
C	Turbine 1st Stage		984	1559	1574	1672	1323	1238	1326	953	983
C	HP Htr. 1-G1 & 1-G2 Steam In.		310	505	513	537	261	391	416	311	308
	Air & Gas - IN H_2O										
C	FD Fan 1-A Discharge		7.35	14.17	13.78	5.47	12.75	4.26	13.09	7.95	9.52
C	FD Fan 1-B Discharge		6.46	13.30	12.75	8.78	11.24	6.66	11.96	6.67	8.33
C	Air Htr. 1-A Air In.		5.99	11.27	11.12	7.58	10.11	5.78	10.29	6.21	7.62
C	Air Htr. 1-B Air In.		5.57	10.49	10.26	7.04	9.11	5.36	9.60	5.50	7.04
C	Air Htr. 1-A Air Out.		4.41	7.18	7.13	3.52	6.47	2.90	6.63	4.20	5.58
C	Air Htr. 1-B Air Out.		4.32	7.19	7.20	3.38	6.50	2.88	6.49	4.12	5.51
C	Furn. Right Windbox		3.82	5.53	5.64	2.35	5.22	2.17	4.98	3.56	4.98
C	Furn. Left Windbox		3.72	5.59	5.70	2.14	5.27	2.23	5.12	3.51	4.96
C	Rt. WDBX to Furn. Diff. P		4.55	6.56	6.54	3.08	6.54	3.16	6.54	4.15	6.15
C	Left WDBX to Furn. Diff. P		5.38	7.01	6.97	3.73	7.01	3.86	7.01	5.17	6.63
C	Furnace		-0.63	-0.23	-0.03	-0.44	-0.60	-0.51	-0.57	-0.52	-0.35
C	Pri. SH Gas Out.		-0.48	-0.25	-0.18	-0.62	-0.56	-0.64	-0.54	-0.59	-0.49
C	Reheater Gas Out.		-0.74	-0.82	-0.68	-0.48	-1.03	-0.36	-0.96	-0.84	-0.74
C	Econ. Gas In.		-1.22	-2.03	-2.10	-2.56	-1.88	-1.81	-2.05	-1.49	-1.29
C	Econ. Gas Out.		-2.78	-5.68	-5.78	-6.22	-4.82	-4.47	-5.13	-3.00	-2.90
C	Air Htr. 1-A Gas In.		-3.97	-7.98	-8.36	-8.91	-6.89	-6.49	-7.12	-4.13	-4.22
C	Air Htr. 1-B Gas In.		-4.12	-7.77	-7.99	-8.89	-6.50	-6.24	-7.20	-4.37	-4.37
C	Air Htr. 1-A Gas Out.		-6.9	-14.3	-14.5	-15.5	-11.6	-11.3	-12.6	-7.5	-7.6
C	Air Htr. 1-B Gas Out.		-6.4	-13.0	-13.1	-14.0	-10.6	-10.1	-11.6	-6.9	-7.1
C	IDF 1-A Disch.		-0.85	-0.00	-0.13	-0.78	-0.26	-1.01	-0.12	-0.73	-0.78
C	IDF 1-B Disch.		-0.90	-0.06	-0.03	-0.92	-0.22	-0.97	-0.09	-0.69	-0.85
C	PAF 1-A Disch. Hdr.		31.50	32.32	33.17	32.87	31.94	32.47	31.89	31.76	31.37
C	PAF 1-B Disch. Hdr.		32.33	33.37	34.33	32.78	32.84	32.29	32.86	32.73	32.26
*B	Pri. Hot Air Duct		30	30	30	30	30	30	30	30	30
	TEMPERATURES										
	Air & Gas - °F										
C	1-A FD Fan Disch.		74	84	76	40	76	47	73	77	68
C	1-B FD Fan Disch.		80	91	81	47	84	56	80	87	78
C	1-A AH Air In.		104	98	88	82	91	99	90	91	112
C	1-B AH Air In.		108	102	91	85	94	105	93	94	116
C	1-A AH Air Out.		564	690	702	698	651	631	637	606	552
C	1-B AH Air Out.		580	718	731	715	665	639	663	630	561
C	1-A AH Gas In.		611	748	762	763	710	684	694	656	605
C	1-B AH Gas In.		608	753	453	767	703	684	702	658	596
C	1-A AH Gas Out.		240	292	276	272	253	251	254	253	236
C	1-B AH Gas Out.		242	291	281	270	257	252	254	261	233

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BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8	9
	Date	1976	5/19	5/19	3/12	5/19	5/12	5/12	5/16	5/21	6/27
	Time		16:15	13:50	07:15	11:00	11:00	09:20	09:30	03:10	09:40
*C	Load	MW	505	506	524	506	422	422	421	320	314
	TEMPERATURES										
	Air & Gas - °F										
C	Econ. N Gas Out.		797	777	836	770	716	706	722	661	610
C	Econ. S Gas Out.		770	768	823	758	685	674	596	655	*NA
C	1-A PA Fan Disch. Hdr.		95	93	68	85	80	74	82	80	101
C	1-B PA Fan Disch. Hdr.		NA	NA	104	NA	NA	NA	NA	NA	NA
C	1-A AH Pri. Air Out.		698	700	732	693	650	639	637	608	561
C	1-B AH Pri. Air Out.		702	694	724	683	643	634	636	608	563
	Steam & Water - °F										
C	Boiler Econ. In.		474	474	478	474	451	452	451	425	417
C	Downcomer 1		674	674	676	674	671	670	670	666	666
C	Downcomer 2		676	676	678	676	672	672	672	667	667
C	Downcomer 3		676	677	678	676	673	672	673	667	668
C	Downcomer 4		680	680	682	680	677	677	677	672	418
C	Downcomer 5		678	678	680	678	674	674	674	669	668
C	Blr. SH ATMP 1-A Stm. In.		836	832	856	835	821	834	829	917	833
C	Blr. SH ATMP 1-B Stm. In.		840	832	873	849	808	813	836	873	823
C	Blr. S SH Hdr. Out.		998	1012	1008	995	1005	1005	995	1006	999
C	Blr. N SH Hdr. Out.		1012	997	1014	1016	1003	1001	1017	999	999
C	Turbine Throttle		1002	1000	1008	1001	1003	1001	1002	1002	NA
C	Blr. S RH ATMP Stm. Out. A		476	475	479	476	574	586	588	427	540
C	Blr. N RH ATMP Stm. Out. B		473	474	482	473	527	585	587	426	539
C	Blr. S RH Hdr. Out. A		982	1002	1014	1000	997	1003	974	998	924
C	Blr. N RH Hdr. Out. B		1026	1011	1015	1017	1002	1004	1023	992	932
C	HP Htr. 1-G1 & 1-G2 Extr. Stm.		616	618	628	617	580	579	580	547	533
C	HP Htr. 1-F1 FW Out.		408	408	412	408	389	389	389	368	NA
C	HP Htr. 1-F2 FW Out.		406	406	412	406	388	388	388	367	356
C	HP Htr. 1-G1 FW Out.		472	472	479	472	451	450	450	424	NA
C	HP Htr. 1-G2 FW Out.		473	473	479	473	451	451	451	424	416
C	HP Htr. 1-G1 Drain		411	412	415	412	391	391	390	367	NA
C	HP Htr. 1-G2 Drain		378	379	378	376	358	356	358	338	332
	PULVERIZER DATA										
C	PLV 1-A Bowl Lower P	IN. H_2O	20.6	20.7	21.7	-0.4	21.0	21.0	-0.4	18.5	17.0
C	PLV 1-B Bowl Lower P	IN. H_2O	24.0	23.8	23.4	23.6	24.2	23.7	23.8	20.0	20.7
C	PLV 1-C Bowl Lower P	IN. H_2O	21.6	21.9	0.2	22.3	23.4	23.7	23.0	19.7	0.1
C	PLV 1-D Bowl Lower P	IN. H_2O	23.0	23.0	23.6	23.0	-0.2	-0.2	23.4	19.6	30.3
C	PLV 1-E Bowl Lower P	IN. H_2O	22.2	-1.1	21.9	22.2	22.3	22.3	21.8	-1.0	18.1
C	PLV 1-F Bowl Lower P	IN. H_2O	-1.5	19.5	18.9	20.1	-0.1	-0.1	0.1	-1.4	16.8
C	PLV 1-A Bowl Diff. P	IN. H_2O	6.90	6.94	7.79	0.44	7.23	7.22	0.44	6.34	5.89
C	PLV 1-B Bowl Diff. P	IN. H_2O	7.88	7.79	8.11	7.68	8.25	8.00	7.86	6.46	6.64
C	PLV 1-C Bowl Diff. P	IN. H_2O	7.15	7.29	0.04	7.18	7.74	7.85	7.65	6.62	0.02
C	PLV 1-D Bowl Diff. P	IN. H_2O	7.66	7.80	8.09	7.73	-0.00	-0.02	7.72	6.68	0.05
C	PLV 1-E Bowl Diff. P	IN. H_2O	6.92	0.12	7.04	6.94	7.17	7.10	6.93	0.19	5.97
C	PLV 1-F Bowl Diff. P	IN. H_2O	0.06	6.73	6.64	6.93	-0.02	-0.03	0.00	0.06	5.78
C	PLV 1-A Coal Air Out. P	IN. H_2O	9.30	9.45	10.13	-1.24	6.05	6.05	-1.37	8.20	7.41
C	PLV 1-B Coal Air Out. P	IN. H_2O	11.97	11.86	11.69	11.74	11.79	11.51	11.89	10.04	10.38
C	PLV 1-C Coal Air Out. P	IN. H_2O	10.51	10.66	-0.13	10.86	11.22	11.32	11.19	9.58	0.17
C	PLV 1-D Coal Air Out. P	IN. H_2O	10.98	11.02	11.15	11.05	0.06	0.06	11.28	9.15	30.20
C	PLV 1-E Coal Air Out. P	IN. H_2O	10.83	-1.25	11.32	10.88	10.77	10.80	10.71	-1.17	8.72
C	PLV 1-F Coal Air Out. P	IN. H_2O	-1.64	9.31	9.08	9.70	0.11	0.11	0.09	-1.38	8.38
C	PLV 1-A Pri. Air In. Flow	0-125%	127	127	125	0	127	127	0	127	123
C	PLV 1-B Pri. Air In. Flow	0-125%	129	128	128	129	129	128	129	128	127
C	PLV 1-C Pri. Air In. Flow	0-125%	129	130	38	129	131	130	129	131	51
C	PLV 1-D Pri. Air In. Flow	0-125%	126	125	126	126	0	0	126	126	31
C	PLV 1-E Pri. Air In. Flow	0-125%	129	0	128	130	126	126	126	0	126
C	PLV 1-F Pri. Air In. Flow	0-125%	0	124	125	125	0	0	0	0	130
C	PLV 1-A Coal Air Disch. Temp.	°F	143	143	143	88	143	143	87	143	146

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BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		10	11	12	13	14	15	16	17	18
	Date	1976	5/23	5/19	5/10	3/16	5/12	3/13	5/18	5/21	5/23
	Time		11:05	18:35	09:50	10:00	13:45	15:30	11:45	01:15	09:10
*C	Load	MW	324	491	497	522	422	400	422	320	323
	TEMPERATURES										
	Air & Gas - °F										
C	Econ. N Gas Out.		642	791	803	803	737	715	748	676	653
C	Econ. S Gas Out.		557	701	788	810	631	722	612	673	538
C	1-A PA Fan Disch. Hdr.		83	94	86	53	86	58	82	82	78
C	1-B PA Fan Disch. Hdr.		*NA	NA	NA	61	NA	80	NA	NA	NA
C	1-A AH Pri. Air Out.		578	702	713	710	661	641	649	619	567
C	1-B AH Pri. Air Out.		574	697	713	699	653	627	648	620	556
	Steam & Water - °F										
C	Boiler Econ. In.		424	471	473	480	452	447	451	424	424
C	Downcomer 1		665	673	673	678	671	672	670	665	665
C	Downcomer 2		668	675	674	680	672	674	672	667	667
C	Downcomer 3		669	676	675	680	673	674	673	668	668
C	Downcomer 4		673	679	679	684	677	678	677	672	673
C	Downcomer 5		670	677	676	681	675	676	674	669	670
C	Blr. SH ATMP 1-A Stm. In.		850	844	865	846	828	827	828	915	855
C	Blr. SH ATMP 1-B Stm. In.		821	851	863	868	819	837	845	870	827
C	Blr. S SH Hdr. Out.		1006	992	1011	999	1004	1003	990	1004	1003
C	Blr. N SH Hdr. Out.		1005	1018	1005	1019	1005	1021	1022	1006	1008
C	Turbine Throttle		1005	1001	1005	1004	1000	1009	999	1003	1003
C	Blr. S RH ATMP Stm. Out. A		552	472	472	481	578	588	588	427	552
C	Blr. N RH ATMP Stm. Out. B		551	470	471	482	500	587	587	427	551
C	Blr. S RH Hdr. Out. A		963	983	982	989	999	998	969	995	973
C	Blr. N RH Hdr. Out. B		978	1027	1021	1030	1004	1012	1037	995	980
C	HP Htr. 1-G1 & 1-G2 Extr. Stm.		546	612	618	624	580	580	577	545	545
C	HP Htr. 1-F1 FW Out.		366	405	407	413	389	386	389	367	367
C	HP Htr. 1-F2 FW Out.		366	404	406	412	388	386	388	366	365
C	HP Htr. 1-G1 FW Out.		424	469	472	480	451	448	450	424	423
C	HP Htr. 1-G2 FW Out.		424	470	472	480	451	448	451	423	424
C	HP Htr. 1-G1 Drain		366	409	410	416	391	387	391	366	366
C	HP Htr. 1-G2 Drain		335	376	376	384	360	359	358	337	334
	PULVERIZER DATA										
C	PLV 1-A Bowl Lower P	IN. H_2O	-0.3	20.6	21.5	21.4	20.7	18.3	-0.5	18.3	-0.3
C	PLV 1-B Bowl Lower P	IN. H_2O	-1.3	24.0	25.3	-0.0	24.0	18.9	24.0	20.6	-1.5
C	PLV 1-C Bowl Lower P	IN. H_2O	19.4	21.5	23.9	24.4	23.2	0.2	23.0	19.5	19.8
C	PLV 1-D Bowl Lower P	IN. H_2O	19.3	22.7	-0.3	23.6	-0.2	19.8	23.6	19.7	19.3
C	PLV 1-E Bowl Lower P	IN. H_2O	19.7	22.0	23.5	22.7	22.0	19.8	21.9	-1.1	19.9
C	PLV 1-F Bowl Lower P	IN. H_2O	18.1	-1.4	22.4	21.2	-0.1	17.6	0.1	-1.3	18.2
C	PLV 1-A Bowl Diff. P	IN. H_2O	0.44	6.83	7.28	7.54	7.11	6.58	0.44	6.31	0.44
C	PLV 1-B Bowl Diff. P	IN. H_2O	0.20	7.74	8.30	0.01	8.18	6.67	7.97	6.61	0.21
C	PLV 1-C Bowl Diff. P	IN. H_2O	6.34	7.12	7.82	8.43	7.72	0.02	7.73	6.53	6.47
C	PLV 1-D Bowl Diff. P	IN. H_2O	6.47	7.60	0.29	8.06	0.02	6.84	7.82	6.72	6.48
C	PLV 1-E Bowl Diff. P	IN. H_2O	6.16	6.84	7.34	7.25	7.16	6.44	6.94	0.17	6.21
C	PLV 1-F Bowl Diff. P	IN. H_2O	6.14	0.06	7.38	7.30	-0.01	6.18	0.00	0.06	6.12
C	PLV 1-A Coal Air Out. P	IN. H_2O	-1.15	9.36	8.93	9.86	6.12	8.37	-1.41	8.17	-1.16
C	PLV 1-B Coal Air Out. P	IN. H_2O	-1.28	12.00	12.55	0.43	11.68	9.55	11.85	10.13	-1.35
C	PLV 1-C Coal Air Out. P	IN. H_2O	9.46	10.50	11.70	11.27	11.09	-0.23	11.14	9.48	9.78
C	PLV 1-D Coal Air Out. P	IN. H_2O	9.34	10.91	-0.70	11.43	0.06	9.45	11.34	9.23	9.36
C	PLV 1-E Coal Air Out. P	IN. H_2O	9.75	10.93	11.51	11.80	10.57	10.29	10.66	-1.35	9.85
C	PLV 1-F Coal Air Out. P	IN. H_2O	9.07	-1.40	10.90	10.60	0.11	8.52	0.09	-1.54	8.98
C	PLV 1-A Pri. Air In. Flow	0-125%	0	127	127	126	127	125	0	127	0
C	PLV 1-B Pri. Air In. Flow	0-125%	31	129	129	42	128	128	129	129	32
C	PLV 1-C Pri. Air In. Flow	0-125%	131	130	130	131	130	0	131	132	131
C	PLV 1-D Pri. Air In. Flow	0-125%	126	125	49	125	0	125	125	126	126
C	PLV 1-E Pri. Air In. Flow	0-125%	129	129	126	128	126	128	126	0	130
C	PLV 1-F Pri. Air In. Flow	0-125%	124	0	126	126	0	125	0	0	124
C	PLV 1-A Coal Air Disch. Temp.	°F	84	143	146	145	144	144	88	143	79

* C - Computer Data; B - Board Data; NA - Not Available.

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8	9
	Date	1976	5/19	5/19	3/12	5/19	5/12	5/12	5/16	5/21	6/27
	Time		16:15	13:50	07:15	11:00	11:00	09:20	09:30	03:10	09:40
*C	Load	MW	505	506	524	506	422	422	421	320	314
	PULVERIZER DATA										
C	PLV 1-B Coal Air Disch. Temp.	°F	144	144	145	143	144	143	144	141	153
C	PLV 1-C Coal Air Disch. Temp.	°F	145	145	49	144	146	146	146	145	*NA
C	PLV 1-D Coal Air Disch. Temp.	°F	142	143	146	142	107	106	142	143	117
C	PLV 1-E Coal Air Disch. Temp.	°F	138	128	142	138	139	140	139	100	142
C	PLV 1-F Coal Air Disch. Temp.	°F	159	142	145	142	118	117	78	110	145
C	PLV 1-A Feeder Coal Flow	10^3 LB/HR	115	115	120	0	116	113	0	85	83
C	PLV 1-B Feeder Coal Flow	10^3 LB/HR	116	116	120	116	119	115	117	87	85
C	PLV 1-C Feeder Coal Flow	10^3 LB/HR	116	166	0	116	117	115	117	87	NA
C	PLV 1-D Feeder Coal Flow	10^3 LB/HR	116	116	118	116	0	0	117	88	NA
C	PLV 1-E Feeder Coal Flow	10^3 LB/HR	116	0	112	116	117	114	117	0	84
C	PLV 1-F Feeder Coal Flow	10^3 LB/HR	0	116	113	116	0	0	0	0	82
C	PLV 1-A Mill	AMPS	70	71	76	0	72	70	0	63	64
C	PLV 1-B Mill	AMPS	74	74	75	72	75	74	74	65	66
C	PLV 1-C Mill	AMPS	73	73	0	72	71	72	73	66	NA
C	PLV 1-D Mill	AMPS	75	75	78	75	0	0	75	65	NA
C	PLV 1-E Mill	AMPS	75	0	76	75	78	76	78	0	66
C	PLV 1-F Mill	AMPS	0	76	73	75	0	0	0	0	66
	FAN DAMPER POSITION - % OPEN										
*B	1-A FD Fan Inlet Vane		78	75	71	74	70	67	71	53	59
B	1-B FD Fan Inlet Vane		77	74	70	72	68	65	70	51	62
B	1-A PA Fan Inlet Vane		36	36	30	35	30	29	31	32	28
B	1-B PA Fan Inlet Vane		31	31	25	30	24	23	25	26	28
	SPRAY VALVE POSITION - % OPEN										
B	1-A SH Spray Valve		29	24	55	40	11	17	22	40	8
B	1-B SH Spray Valve		21	13	27	24	8	12	0	46	12
B	1-A RH Spray Valve		46	55	100	43	2	1	0	13	0
B	1-B RH Spray Valve		34	50	100	32	1	0	0	10	0
	MISCELLANEOUS										
B	Burner Tilt	± DEGREES	0°	-4°	-3°	-9°	-4°	+1°	+11°	+6°	+6°
B	Aux. Air Dampers	% OPEN	39	29	66	31	21	17	25	0	0
B	1-A Fuel/Air Dampers	% OPEN	100	100	54	100	100	100	100	78	77
B	1-B Fuel/Air Dampers	% OPEN	100	100	55	100	100	100	100	81	77
B	1-C Fuel/Air Dampers	% OPEN	100	100	100	100	100	37	100	86	100
B	1-D Fuel/Air Dampers	% OPEN	100	100	55	100	0	100	100	81	100
B	1-E Fuel/Air Dampers	% OPEN	100	100	50	100	100	100	100	100	75
B	1-F Fuel/Air Dampers	% OPEN	100	100	44	100	100	0	0	100	75
B	1-A Pri. Air Fan	AMPS	173	173	170	175	166	165	165	168	160
B	1-B Pri. Air Fan	AMPS	183	184	180	185	173	173	175	175	195
B	1-A ID Fan	AMPS	460	460	480	460	370	350	390	260	300
B	1-B ID Fan	AMPS	410	390	400	390	330	300	320	300	280
B	1-A FD Fan	AMPS	218	205	197	205	193	180	195	158	169
B	1-B FD Fan	AMPS	198	180	183	183	180	161	181	145	150
B	1-A ID Fan	RPM	485	480	480	477	418	390	435	298	330
B	1-B ID Fan	RPM	495	488	480	488	423	397	438	305	NA
B	1-A Blr. Circ. Wtr. Pump	AMPS	74	75	73	75	80	80	80	80	83
B	1-B Blr. Circ. Wtr. Pump	AMPS	78	79	76	79	81	82	83	83	87
B	1-C Blr. Circ. Wtr. Pump	AMPS	73	73	71	75	76	78	78	78	NA
B	1-D Blr. Circ. Wtr. Pump	AMPS	74	76	74	78	80	81	80	81	84
C	N Drum Level ± Norm. H_2O Level	IN.	-0.73	-0.42	-0.64	-0.80	-0.48	-0.82	-0.76	-0.79	-0.69
C	S Drum Level ± Norm. H_2O Level	IN.	-3.26	-0.27	-2.38	-1.40	-1.45	-2.23	-2.43	-2.56	-2.57
C	Flue Gas Combustibles	%	0.063	0.067	0.062	0.066	0.062	0.065	0.062	0.060	0.055
C	Flue Gas Oxygen	%	3.3	2.6	3.5	3.4	3.9	3.6	4.1	4.0	5.1
C	Baronmetric Press.	IN. HGA	29.76	29.83	28.95	29.97	30.04	30.09	29.54	30.01	30.10

* C - Computer Data; B - Board Data; NA - Not Available.

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		10	11	12	13	14	15	16	17	18
	Date	1976	5/23	5/19	5/10	3/16	5/12	3/13	5/16	5/21	5/23
	Time		11:05	18:35	09:50	10:00	13:45	15:30	11:45	01:15	09:10
*C	Load	MW	324	491	497	522	422	400	422	320	323
	PULVERIZER DATA										
C	PLV 1-B Coal Air Disch. Temp.	°F	130	143	152	83	144	146	144	144	152
C	PLV 1-C Coal Air Disch. Temp.	°F	144	145	150	149	147	45	146	145	143
C	PLV 1-D Coal Air Disch. Temp.	°F	141	143	91	147	110	147	143	143	138
C	PLV 1-E Coal Air Disch. Temp.	°F	138	138	152	143	139	142	139	111	138
C	PLV 1-F Coal Air Disch. Temp.	°F	142	141	162	146	121	145	78	118	141
C	PLV 1-A Feeder Coal Flow	10^3LB/HR	*NA	106	114	116	117	86	0	85	0
C	PLV 1-B Feeder Coal Flow	10^3LB/HR	NA	108	116	0	118	87	117	87	0
C	PLV 1-C Feeder Coal Flow	10^3LB/HR	87	107	114	114	118	0	117	86	88
C	PLV 1-D Feeder Coal Flow	10^3LB/HR	88	108	0	116	0	86	118	87	89
C	PLV 1-E Feeder Coal Flow	10^3LB/HR	88	107	114	116	117	87	118	0	89
C	PLV 1-F Feeder Coal Flow	10^3LB/HR	86	0	112	115	0	85	0	0	70
C	PLV 1-A Mill	AMPS	0	68	73	72	71	65	0	63	0
C	PLV 1-B Mill	AMPS	0	72	73	0	75	65	75	67	0
C	PLV 1-C Mill	AMPS	67	72	73	74	73	0	74	66	66
C	PLV 1-D Mill	AMPS	65	74	0	75	0	67	75	66	66
C	PLV 1-E Mill	AMPS	67	75	75	75	78	67	77	0	66
C	PLV 1-F Mill	AMPS	66	0	70	75	0	67	0	0	65
	FAN DAMPER POSITION - % OPEN										
*B	1-A FD Fan Inlet Vane		57	79	77	70	74	64	75	60	61
B	1-B FD Fan Inlet Vane		56	77	76	70	73	63	74	59	60
B	1-A PA Fan Inlet Vane		31	36	37	28	30	29	31	32	31
B	1-B PA Fan Inlet Vane		25	31	32	24	25	24	26	26	25
	SPRAY VALVE POSITION - % OPEN										
B	1-A SH Spray Valve		14	50	68	65	15	23	23	39	15
B	1-B SH Spray Valve		8	33	57	28	3	6	4	47	12
B	1-A RH Spray Valve		0	48	81	61	4	0	0	15	0
B	1-B RH Spray Valve		0	34	58	62	3	0	0	10	0
	MISCELLANEOUS										
B	Burner Tilt	± DEGREES	+5°	+2°	-4°	-3°	-3°	+1°	+6°	+9°	+6°
B	Aux. Air Dampers	% OPEN	0	40	34	81	30	50	39	0	0
B	1-A Fuel/Air Dampers	% OPEN	0	100	100	51	100	32	100	76	0
B	1-B Fuel/Air Dampers	% OPEN	0	100	100	100	100	33	100	81	0
B	1-C Fuel/Air Dampers	% OPEN	87	100	100	51	100	100	100	84	89
B	1-D Fuel/Air Dampers	% OPEN	83	100	100	54	0	34	100	80	84
B	1-E Fuel/Air Dampers	% OPEN	81	100	100	52	100	33	100	0	82
B	1-F Fuel/Air Dampers	% OPEN	78	100	100	51	100	33	0	0	79
B	1-A Pri. Air Fan	AMPS	169	173	175	171	165	175	166	165	168
B	1-B Pri. Air Fan	AMPS	179	183	185	185	170	182	175	175	178
B	1-A ID Fan	AMPS	280	500	490	500	410	390	443	300	300
B	1-B ID Fan	AMPS	310	420	420	430	340	320	367	310	310
B	1-A FD Fan	AMPS	166	225	213	204	203	187	210	171	175
B	1-B FD Fan	AMPS	155	198	196	197	187	175	195	158	165
B	1-A ID Fan	RPM	320	488	482	480	445	430	463	345	338
B	1-B ID Fan	RPM	323	496	500	490	457	430	478	340	345
B	1-A Blr. Circ. Wtr. Pump	AMPS	83	73	73	75	79	80	79	79	81
B	1-B Blr. Circ. Wtr. Pump	AMPS	84	77	77	76	80	82	81	82	84
B	1-C Blr. Circ. Wtr. Pump	AMPS	79	73	72	71	75	78	75	77	78
B	1-D Blr. Circ. Wtr. Pump	AMPS	84	74	73	75	79	79	77	80	83
C	N Drum Level ± Norm. H_2O Level	IN.	-0.51	-0.76	-0.75	-0.68	-0.54	-0.61	-0.47	-0.53	-0.62
C	S Drum Level ± Norm. H_2O Level	IN.	-2.36	-3.22	-3.12	-2.88	-1.33	-1.48	-3.26	-2.51	-2.22
C	Flue Gas Combustibles	%	0.064	0.064	0.061	0.062	0.062	0.065	0.062	0.059	0.065
C	Flue Gas Oxygen	%	4.4	3.5	3.8	4.3	4.9	5.5	5.1	5.8	6.0
C	Baronmetric Press.	IN. HGA	30.10	29.73	29.66	29.82	29.91	29.99	29.55	29.92	30.14

* C - Computer Data; B - Board Data; NA - Not Available.

OVERFIRE AIR OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8
	Date	1976	3/17	3/17	3/20	3/20	3/22	3/20	3/20	3/20
	Time		09:30	10:45	16:50	19:45	17:00	10:05	12:00	14:30
*C	Load	MW	517	512	524	525	526	521	522	522
	FLOWS - 10^3LB/HR									
C	Feedwater		3083	3084	3367	3331	3233	3480	3372	3388
C	Superheat Spray L		101	102	14	56	95	0	0	0
C	Superheat Spray R		109	105	43	42	94	12	25	31
C	Reheat Spray L		78	78	42	48	50	10	35	39
C	Reheat Spray R		82	82	66	70	72	15	59	63
C	BFP Turb. Extr. Stm. Flow 1-A		0	0	0	0	0	0	0	0
C	BFP Turb. Extr. Stm. Flow 1-B		0	0	0	0	0	0	0	0
C	BFP Turb. Mn. Stm. Flow Combined		7.6	7.5	8.2	8.2	8.0	8.5	8.4	8.2
C	Hot Air to Burners L Windbox		1608	1604	1609	1564	1582	1486	1480	1486
C	Hot Air to Burners R Windbox		1557	1556	1576	1535	1539	1474	1472	1470
	PRESSURES									
	Steam & Water - PSIG									
C	Feedwater to Econ.		2723	2722	2750	2750	2741	2766	2754	2756
C	Boiler Drum		2673	2672	2689	2689	2687	2699	2692	2692
C	Turbine Throttle		2400	2402	2397	2399	2398	2401	2403	2399
C	Turbine 1st Stage		1624	1616	1677	1682	1680	1689	1680	1682
C	HP Htr. 1-G1 & 1-G2 Steam In.		529	527	537	540	541	528	536	536
	Air & Gas - IN H_2O									
C	FD Fan 1-A Discharge		5.56	5.54	6.04	5.77	5.38	5.20	5.42	5.32
C	FD Fan 1-B Discharge		9.16	9.13	10.20	9.63	8.91	8.54	8.84	8.69
C	Air Htr. 1-A Air In.		7.75	7.77	8.41	8.10	7.50	7.07	7.23	7.21
C	Air Htr. 1-B Air In.		7.19	7.18	7.82	7.62	6.93	6.56	6.63	6.57
C	Air Htr. 1-A Air Out.		3.60	3.64	4.00	3.80	3.39	3.36	3.43	3.38
C	Air Htr. 1-B Air Out.		3.38	3.46	3.92	3.73	3.40	3.37	3.34	3.36
C	Furn. Right Windbox		2.22	2.25	2.42	2.47	2.27	2.10	2.12	2.16
C	Furn. Left Windbox		2.20	2.25	2.52	2.50	2.25	2.14	2.12	2.21
C	Rt. WDBX to Furn. Diff. P		3.39	3.43	3.16	3.18	3.23	3.18	3.13	3.18
C	Left WDBX to Furn. Diff. P		3.96	4.02	3.92	3.99	3.87	4.01	3.90	3.96
C	Furnace		-0.53	-0.49	-0.18	-0.27	-0.48	-0.39	-0.56	-0.60
C	Pri. SH Gas Out.		-0.63	-0.70	-0.50	-0.57	-0.72	-0.70	-0.65	-0.81
C	Reheater Gas Out.		-0.56	-0.63	-0.31	-0.47	-0.64	-0.42	-0.58	-0.61
C	Econ. Gas In.		-2.48	-2.49	-2.04	-2.32	-2.45	-2.02	-2.20	-2.24
C	Econ. Gas Out.		-6.45	-6.46	-5.84	-5.94	-6.11	-5.38	-5.64	-5.58
C	Air Htr. 1-A Gas In.		-8.93	-8.92	-7.96	-8.13	-8.72	-7.67	-7.68	-7.64
C	Air Htr. 1-B Gas In.		-8.60	-8.60	-7.74	-7.94	-8.19	-7.08	-7.38	-7.42
C	Air Htr. 1-A Gas Out.		-15.5	-15.6	-14.6	-14.6	-15.4	-13.0	-13.6	-13.6
C	Air Htr. 1-B Gas Out.		-14.1	-14.0	-13.1	-13.3	-13.9	-11.9	-12.2	-12.4
C	IDF 1-A Discharge		-0.58	-0.58	-0.04	-0.23	-0.44	-0.09	-0.10	-0.11
C	IDF 1-B Discharge		-0.62	-0.63	-0.04	-0.20	-0.39	0.11	-0.08	-0.07
C	PAF 1-A Discharge Hdr.		32.95	32.93	33.42	33.24	33.00	33.48	33.53	33.44
C	PAF 1-B Discharge Hdr.		32.74	32.80	33.40	33.18	32.87	33.32	33.42	33.44
*B	Pri. Hot Air Duct		30	30	30	30	30	30	30	30
	TEMPERATURES									
	Air & Gas - °F									
C	1-A FD Fan Discharge		44	45	72	67	59	77	75	77
C	1-B FD Fan Discharge		52	53	81	76	67	83	82	85
C	1-A AH Air In.		75	75	86	82	79	93	90	93
C	1-B AH Air In.		78	78	88	84	82	96	93	94
C	1-A AH Air Out.		712	714	696	707	691	653	673	681
C	1-B AH Air Out.		734	736	721	739	720	673	696	705
C	1-A AH Gas In.		778	780	758	769	757	709	730	738
C	1-B AH Gas In.		783	785	768	785	762	714	738	746
C	1-A AH Gas Out.		274	274	281	282	272	266	274	279
C	1-B AH Gas Out.		275	275	280	286	275	269	272	278

* C - Computer Data; B - Board Data; NA - Not Available.

OVERFIRE AIR OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		9	10	11	12	13	14	15	16
	Date	1976	3/24	3/24	3/24	6/24	6/24	6/24	3/25	6/30
	Time		00:45	02:20	04:00	12:00	13:20	09:45	10:15	09:50
*C	Load	MW	473	473	472	524	525	523	510	526
	FLOWS - 10^3LB/HR									
C	Feedwater		2912	2834	2800	3297	3289	3327	3079	3255
C	Superheat Spray L		56	59	84	70	82	70	97	85
C	Superheat Spray R		79	78	91	79	94	78	98	95
C	Reheat Spray L		45	46	57	28	50	10	67	33
C	Reheat Spray R		61	62	70	63	77	50	76	60
C	BFP Turb. Extr. Stm. Flow 1-A		0	0	0	43	43	43	0	43
C	BFP Turb. Extr. Stm. Flow 1-B		0	0	0	77	76	76	0	89
C	BFP Turb. Mn. Stm. Flow Combined		6.8	6.4	6.1	8.1	8.0	8.1	7.6	8.0
C	Hot Air to Burners L Windbox		1668	1658	1543	1767	1774	1785	1477	1739
C	Hot Air to Burners R Windbox		1614	1613	1510	1663	1668	1683	1454	1637
	PRESSURES									
	Steam & Water - PSIG									
C	Feedwater to Econ.		2691	2684	2675	2746	2745	2744	2720	2751
C	Boiler Drum		2644	2637	2631	2691	2691	2686	2670	2698
C	Turbine Throttle		2405	2401	2400	2401	2402	2402	2394	2405
C	Turbine 1st Stage		1496	1465	1456	1680	1679	1679	1614	1687
C	HP Htr. 1-G1 & 1-G2 Steam In.		485	478	480	538	538	531	522	535
	Air & Gas - IN H_2O									
C	FD Fan 1-A Discharge		6.24	6.08	5.58	14.98	15.15	15.12	5.37	14.75
C	FD Fan 1-B Discharge		11.72	10.30	9.30	13.58	13.55	13.71	8.52	13.35
C	Air Htr. 1-A Air In.		8.94	8.54	7.70	11.51	11.59	11.63	7.53	11.45
C	Air Htr. 1-B Air In.		8.41	7.93	7.11	10.42	10.54	10.56	6.72	10.34
C	Air Htr. 1-A Air Out.		4.44	4.11	3.57	7.05	7.01	7.03	3.59	7.13
C	Air Htr. 1-B Air Out.		4.53	4.13	3.61	7.05	7.00	6.98	3.58	7.01
C	Furn. Right Windbox		3.14	2.68	2.39	5.41	5.33	5.37	2.39	5.38
C	Furn. Left Windbox		3.06	2.57	2.39	5.40	5.29	5.31	2.43	5.38
C	Rt. WDBX to Furn. Diff. P		3.67	3.16	3.20	5.47	5.43	5.45	3.14	5.46
C	Left WDBX to Furn. Diff. P		4.24	3.92	4.00	6.13	6.13	6.09	3.94	6.13
C	Furnace		-0.14	-0.23	-0.44	-0.53	-0.61	-0.43	-0.45	-0.43
C	Pri. SH Gas Out.		-0.38	-0.27	-0.76	-0.68	-0.71	-0.65	-0.67	-0.64
C	Reheater Gas Out.		-0.25	-0.16	-0.59	-1.18	-1.25	-1.11	-0.54	-1.08
C	Econ. Gas In.		-1.99	-2.00	-2.36	-2.23	-2.36	-2.31	-2.27	-2.23
C	Econ. Gas Out.		-6.00	-5.90	-5.76	-6.52	-6.64	-6.51	-5.76	-6.21
C	Air Htr. 1-A Gas In.		-8.30	-8.39	-7.88	-8.55	-8.82	-8.86	-7.72	-8.48
C	Air Htr. 1-B Gas In.		-7.70	-7.82	-7.26	-8.39	-8.68	-8.71	-7.39	-8.47
C	Air Htr. 1-A Gas Out.		-14.8	-14.8	-14.0	-15.2	-15.5	-15.5	-14.0	-14.6
C	Air Htr. 1-B Gas Out.		-13.2	-13.4	-12.6	-14.2	-14.7	-14.6	-12.7	-13.9
C	IDF 1-A Discharge		-0.16	-0.28	-0.36	0.29	0.21	0.26	-0.35	0.07
C	IDF 1-B Discharge		0.05	-0.12	-0.21	0.36	0.28	0.32	-0.29	0.04
C	PAF 1-A Disch. Hdr.		32.92	33.00	32.86	32.61	32.60	32.50	33.22	32.82
C	PAF 1-B Disch. Hdr.		32.92	32.86	32.77	33.95	33.88	33.75	33.09	33.49
*B	Pri. Hot Air Duct		30	30	30	30	30	30	30	30
	TEMPERATURES									
	Air & Gas - °F									
C	1-A FD Fan Disch.		66	62	60	78	80	75	59	75
C	1-B FD Fan Disch.		75	71	70	87	90	83	70	79
C	1-A AH Air In.		80	77	76	91	92	87	79	86
C	1-B AH Air In.		83	80	79	92	94	88	82	87
C	1-A AH Air Out.		693	698	701	665	670	658	695	663
C	1-B AH Air Out.		716	720	725	692	702	681	722	677
C	1-A AH Gas In.		758	764	764	720	725	714	758	722
C	1-B AH Gas In.		760	767	768	736	744	723	764	725
C	1-A AH Gas Out.		272	273	273	265	270	260	272	260
C	1-B AH Gas Out.		272	270	274	271	275	265	283	264

* C - Computer Data; B - Board Data; NA - Not Available.

OVERFIRE AIR OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		17	18	19	20	21	22	23	24
	Date	1976	6/25	6/30	6/29	6/25	6/26	6/25	6/27	6/29
	Time		11:15	08:35	08:50	14:45	10:30	16:25	11:35	01:30
*C	Load	MW	524	526	523	517	419	422	316	322
	FLOWS - 10^3 LB/HR									
C	Feedwater		3262	3284	3262	3203	2651	2517	2062	1891
C	Superheat Spray L		138	80	88	101	35	77	0	56
C	Superheat Spray R		103	100	89	100	34	80	2	61
C	Reheat Spray L		40	23	40	53	0	0	0	0
C	Reheat Spray R		68	53	58	78	2	37	3	3
C	BFP Turb. Extr. Stm. Flow 1-A		43	43	43	42	43	39	34	39
C	BFP Turb. Extr. Stm. Flow 1-B		76	89	89	74	81	72	89	89
C	BFP Turb. Mn. Stm. Flow Combined		8.3	8.1	8.3	7.8	8.6	6.3	0.0	7.1
C	Hot Air to Burners L Windbox		1793	1777	1611	1704	1453	1346	1006	1022
C	Hot Air to Burners R Windbox		1674	1649	1529	1607	1365	1241	944	952
	PRESSURES									
	Steam & Water - PSIG									
C	Feedwater to Econ.		2739	2751	2751	2745	2652	2638	2571	2559
C	Boiler Drum		2688	2699	2696	2694	2607	2598	2533	2527
C	Turbine Throttle		2411	2406	2403	2416	2405	2404	2408	2405
C	Turbine 1st Stage		1671	1697	1685	1644	1305	1291	984	975
C	HP Htr. 1-G1 & 1-G2 Steam In.		534	535	535	499	411	416	306	309
	Air & Gas - IN H_2O									
C	FD Fan 1-A Discharge		15.24	14.86	14.19	14.69	12.78	10.97	6.36	6.51
C	FD Fan 1-B Discharge		13.82	13.27	12.57	13.36	11.02	9.26	4.99	5.26
C	Air Htr. 1-A Air In.		11.76	11.26	11.02	11.30	9.78	8.35	4.66	4.80
C	Air Htr. 1-B Air In.		10.71	10.39	9.89	10.09	8.71	7.23	3.95	4.09
C	Air Htr. 1-A Air Out.		7.09	7.12	6.91	6.90	6.34	5.28	2.86	2.27
C	Air Htr. 1-B Air Out.		6.95	6.91	6.76	6.82	6.42	5.32	2.76	2.87
C	Furn. Right Windbox		5.41	5.33	5.30	5.36	5.41	4.28	2.33	2.42
C	Furn. Left Windbox		5.40	5.35	5.36	5.29	5.39	4.00	2.26	2.42
C	Rt. WDBX to Furn. Diff. P		5.46	5.41	5.43	5.45	5.44	4.03	1.35	1.56
C	Left WDBX to Furn. Diff. P		6.44	6.02	6.07	6.17	6.15	5.12	3.00	3.10
C	Furnace		-0.52	-0.47	-0.54	-0.54	-0.52	-0.53	-0.51	-0.54
C	Pri. SH Gas Out.		-0.74	-0.60	-0.67	-0.92	-0.70	-0.77	-0.71	-0.64
C	Reheater Gas Out.		-1.24	-1.03	-1.12	-1.38	-1.03	-1.13	-0.90	-0.85
C	Econ. Gas In.		-2.43	-2.21	-2.24	-2.33	-1.70	-1.80	-1.26	-1.32
C	Econ. Gas Out.		-6.68	-6.18	-5.83	-6.32	-4.43	-4.44	-2.71	-2.77
C	Air Htr. 1-A Gas In.		-8.79	-8.50	-7.78	-8.52	-6.28	-6.09	-3.81	-3.87
C	Air Htr. 1-B Gas In.		-8.83	-8.51	-7.83	-8.50	-6.14	-6.26	-3.99	-4.02
C	Air Htr. 1-A Gas Out.		-15.6	-14.7	-13.8	-14.8	-10.6	-10.7	-6.29	-6.53
C	Air Htr. 1-B Gas Out.		-14.6	-14.2	-13.2	-14.2	-9.9	-10.2	-6.19	-6.46
C	IDF 1-A Discharge		0.18	0.11	-0.01	0.09	-0.26	-0.23	-0.32	-0.50
C	IDF 1-B Discharge		0.11	0.06	0.06	0.13	0.04	-0.16	-0.32	-0.49
C	PAF 1-A Disch. Hdr.		32.63	32.79	32.77	32.74	31.73	32.50	31.75	31.84
C	PAF 1-B Disch. Hdr.		33.78	33.77	34.16	33.89	32.61	33.76	32.64	32.98
*B	Pri. Hot Air Duct		30	30	30	30	30	30	30	30
	TEMPERATURES									
	Air & Gas - °F									
C	1-A FD Fan Disch.		81	74	73	87	88	89	89	83
C	1-B FD Fan Disch.		86	78	81	91	93	95	94	90
C	1-A AH Air In.		93	84	85	99	100	102	102	96
C	1-B AH Air In.		93	85	87	101	103	104	104	97
C	1-A AH Air Out.		667	651	665	680	606	634	535	568
C	1-B AH Air Out.		695	657	690	708	627	661	555	592
C	1-A AH Gas In.		724	711	725	734	654	687	580	614
C	1-B AH Gas In.		737	712	732	750	663	702	584	629
C	1-A AH Gas Out.		270	255	259	277	244	259	222	226
C	1-B AH Gas Out.		273	255	270	282	262	275	233	241

* C - Computer Data; B - Board Data; NA - Not Available.

OVERFIRE AIR OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8
	Date	1976	3/17	3/17	3/20	3/20	3/22	3/20	3/20	3/20
	Time		09:30	10:45	16:50	19:45	17:00	10:05	12:00	14:30
*C	Load	MW	517	512	524	525	526	521	522	522
	TEMPERATURES									
	Air & Gas - °F									
C	Econ. N Gas Out.		810	812	800	817	796	748	774	777
C	Econ. S Gas Out.		813	815	790	790	796	749	766	770
C	1-A PA Fan Disch. Hdr.		56	57	84	79	70	88	88	90
C	1-B PA Fan Disch. Hdr.		72	72	95	90	85	108	98	102
C	1-A AH Pri. Air Out.		725	727	707	717	704	661	682	690
C	1-B AH Pri. Air Out.		717	718	702	720	696	656	677	686
	Steam & Water - °F									
C	Boiler Econ. In.		477	477	478	480	480	476	478	478
C	Downcomer 1		676	676	678	678	678	679	679	679
C	Downcomer 2		679	678	680	680	679	681	680	680
C	Downcomer 3		679	679	680	680	680	681	681	680
C	Downcomer 4		682	682	684	684	684	685	684	683
C	Downcomer 5		680	680	681	681	681	683	682	682
C	Blr. SH ATMP 1-A Stm. In.		845	845	811	819	838	796	810	809
C	Blr. SH ATMP 1-B Stm. In.		847	849	830	843	846	808	823	820
C	Blr. S SH Hdr. Out.		*NA	NA	NA	NA	NA	NA	NA	1009
C	Blr. N SH Hdr. Out.		NA	NA	NA	NA	NA	NA	NA	1018
C	Turbine Throttle		1003	1004	1005	1006	1005	996	1006	1008
C	Blr. S RH ATMP Stm. Out. A		478	478	482	482	482	602	483	482
C	Blr. N RH ATMP Stm. Out. B		480	480	482	481	482	521	482	482
C	Blr. S RH Hdr. Out. A		991	992	991	991	997	989	988	993
C	Blr. N RH Hdr. Out. B		1019	1022	1017	1020	1025	1026	1022	1023
C	HP Htr. 1-G1 & 1-G2 Extr. Stm.		623	622	624	625	626	613	623	626
C	HP Htr. 1-F1 FW Out.		411	411	412	412	413	410	412	411
C	HP Htr. 1-F2 FW Out.		411	410	412	412	413	410	411	411
C	HP Htr. 1-G1 FW Out.		478	477	480	480	481	477	479	479
C	HP Htr. 1-G2 FW Out.		478	477	479	480	481	477	479	479
C	HP Htr. 1-G1 Drain		414	413	416	416	417	414	416	416
C	HP Htr. 1-G2 Drain		382	380	384	382	382	380	384	384
	PULVERIZER DATA									
C	PLV 1-A Bowl Lower P	IN. H_2O	21.4	21.2	21.6	21.6	21.0	21.1	21.2	21.2
C	PLV 1-B Bowl Lower P	IN. H_2O	-0.03	-0.03	0.03	0.02	0.02	0.04	0.04	0.04
C	PLV 1-C Bowl Lower P	IN. H_2O	24.4	24.1	23.0	23.1	24.6	22.1	22.2	22.1
C	PLV 1-D Bowl Lower P	IN. H_2O	23.3	23.5	23.9	23.0	23.2	23.1	23.1	23.1
C	PLV 1-E Bowl Lower P	IN. H_2O	22.5	22.5	22.4	22.7	22.0	21.8	22.0	21.9
C	PLV 1-F Bowl Lower P	IN. H_2O	21.0	20.8	21.2	21.2	22.2	20.9	20.7	20.4
C	PLV 1-A Bowl Diff. P	IN. H_2O	7.50	7.37	7.29	7.44	7.35	7.24	7.24	7.31
C	PLV 1-B Bowl Diff. P	IN. H_2O	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
C	PLV 1-C Bowl Diff. P	IN. H_2O	8.40	8.35	7.89	8.06	8.59	7.74	7.86	7.75
C	PLV 1-D Bowl Diff. P	IN. H_2O	7.99	8.03	8.05	8.19	8.06	7.79	7.90	7.93
C	PLV 1-E Bowl Diff. P	IN. H_2O	7.24	7.22	6.97	7.11	7.07	6.84	6.96	6.98
C	PLV 1-F Bowl Diff. P	IN. H_2O	7.19	7.14	6.98	7.07	6.94	6.91	6.92	6.88
C	PLV 1-A Coal Air Out. P	IN. H_2O	9.71	9.83	10.40	10.19	10.43	9.97	10.32	10.34
C	PLV 1-B Coal Air Out. P	IN. H_2O	0.40	0.40	0.43	0.45	0.40	0.43	0.43	0.42
C	PLV 1-C Coal Air Out. P	IN. H_2O	11.24	10.97	10.94	11.00	11.34	10.22	10.37	10.34
C	PLV 1-D Coal Air Out. P	IN. H_2O	11.34	11.26	11.55	11.49	11.00	11.15	11.14	11.06
C	PLV 1-E Coal Air Out. P	IN. H_2O	11.66	11.59	11.90	12.08	11.45	11.42	11.60	11.54
C	PLV 1-F Coal Air Out. P	IN. H_2O	10.33	10.28	10.44	10.59	9.86	10.08	10.24	10.23
C	PLV 1-A Pri. Air In. Flow	0-125%	126	126	126	126	126	125	126	125
C	PLV 1-B Pri. Air In. Flow	0-125%	42	42	41	42	43	43	42	42
C	PLV 1-C Pri. Air In. Flow	0-125%	131	130	131	130	131	131	131	131
C	PLV 1-D Pri. Air In. Flow	0-125%	125	125	126	126	125	126	125	126
C	PLV 1-E Pri. Air In. Flow	0-125%	128	127	128	128	128	129	128	128
C	PLV 1-F Pri. Air In. Flow	0-125%	124	124	125	125	125	125	125	126
C	PLV 1-A Coal Air Disch. Temp.	°F	144	144	145	145	145	145	145	145

* C - Computer Data; B - Board Data; NA - Not Available.

OVERFIRE AIR OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		9	10	11	12	13	14	15	16
	Date	1976	3/24	3/24	3/24	6/24	6/24	6/24	3/25	6/30
	Time		00:45	02:20	04:00	12:00	13:20	09:45	10:15	09:50
*C	Load	MW	473	473	472	524	525	523	510	526
	TEMPERATURES									
	Air & Gas - °F									
C	Econ. N Gas Out.		788	787	785	750	756	740	795	738
C	Econ. S Gas Out.		800	807	800	744	748	744	743	745
C	1-A PA Fan Disch. Hdr.		77	72	72	90	91	85	70	86
C	1-B PA Fan Disch. Hdr.		102	92	92	*NA	NA	NA	95	NA
C	1-A AH Pri. Air Out.		705	712	713	678	684	671	707	676
C	1-B AH Pri. Air Out.		693	698	705	680	688	668	705	665
	Steam & Water - °F									
C	Boiler Econ. In.		470	467	468	467	467	465	478	467
C	Downcomer 1		675	673	672	675	675	676	674	676
C	Downcomer 2		677	675	674	677	677	677	676	677
C	Downcomer 3		677	676	676	677	677	677	678	677
C	Downcomer 4		681	680	680	682	681	681	681	681
C	Downcomer 5		678	678	677	679	678	678	683	679
C	Blr. SH ATMP 1-A Stm. In.		838	841	849	830	849	824	840	845
C	Blr. SH ATMP 1-B Stm. In.		834	839	851	847	850	843	846	836
C	Blr. S SH Hdr. Out.		1006	1004	1003	996	1013	1004	1002	1010
C	Blr. N SH Hdr. Out.		1010	1007	1009	993	1010	1003	1013	998
C	Turbine Throttle		1003	1004	1004	991	1006	1000	1004	NA
C	Blr. S RH ATMP Stm. Out. A		471	467	466	481	479	486	476	481
C	Blr. N RH ATMP Stm. Out. B		470	466	467	478	478	481	477	479
C	Blr. S RH Hdr. Out. A		1006	1004	993	973	969	992	989	1003
C	Blr. N RH Hdr. Out. B		1008	1010	1017	1022	1021	1014	1032	1000
C	HP Htr. 1-G1 & 1-G2 Extr. Stm.		606	605	604	615	629	616	621	623
C	HP Htr. 1-F1 FW Out.		404	402	402	129	132	125	409	428
C	HP Htr. 1-F2 FW Out.		403	401	402	400	400	399	408	400
C	HP Htr. 1-G1 FW Out.		468	467	467	208	208	208	476	191
C	HP Htr. 1-G2 FW Out.		469	467	467	466	467	466	476	467
C	HP Htr. 1-G1 Drain		406	404	404	120	120	119	412	100
C	HP Htr. 1-G2 Drain		374	372	372	374	376	373	376	407
	PULVERIZER DATA									
C	PLV 1-A Bowl Lower P	IN. H_2O	20.1	20.0	19.7	20.7	20.7	20.6	20.6	20.4
C	PLV 1-B Bowl Lower P	IN. H_2O	24.0	23.3	22.7	23.9	23.8	23.6	23.1	24.6
C	PLV 1-C Bowl Lower P	IN. H_2O	22.0	22.3	22.2	0.09	0.09	0.09	22.9	0.09
C	PLV 1-D Bowl Lower P	IN. H_2O	0.30	0.30	0.30	22.3	22.2	22.1	0.20	21.7
C	PLV 1-E Bowl Lower P	IN. H_2O	21.0	21.0	20.8	21.8	21.9	21.9	21.5	22.8
C	PLV 1-F Bowl Lower P	IN. H_2O	18.7	18.8	18.5	21.4	21.4	21.3	20.1	21.2
C	PLV 1-A Bowl Diff. P	IN. H_2O	6.85	6.85	6.87	6.93	6.91	6.84	7.17	6.79
C	PLV 1-B Bowl Diff. P	IN. H_2O	7.73	7.59	7.45	7.84	7.77	7.72	7.90	7.91
C	PLV 1-C Bowl Diff. P	IN. H_2O	7.59	7.67	7.74	0.0	0.02	0.01	7.97	0.0
C	PLV 1-D Bowl Diff. P	IN. H_2O	0.05	0.05	0.05	7.33	7.34	7.23	0.05	7.16
C	PLV 1-E Bowl Diff. P	IN. H_2O	6.75	6.73	6.76	7.16	7.10	7.10	6.96	7.43
C	PLV 1-F Bowl Diff. P	IN. H_2O	6.39	6.36	6.40	7.13	7.14	7.09	6.87	6.93
C	PLV 1-A Coal Air Out. P	IN. H_2O	9.92	9.78	9.43	9.40	9.46	9.50	10.12	9.36
C	PLV 1-B Coal Air Out. P	IN. H_2O	12.64	12.18	11.70	11.93	11.86	11.82	11.67	12.49
C	PLV 1-C Coal Air Out. P	IN. H_2O	10.48	10.50	10.16	0.05	0.04	0.06	4.90	0.0
C	PLV 1-D Coal Air Out. P	IN. H_2O	0.22	0.21	0.21	10.97	10.81	10.74	0.21	10.51
C	PLV 1-E Coal Air Out. P	IN. H_2O	11.10	11.06	10.72	10.71	10.62	10.58	11.20	11.10
C	PLV 1-F Coal Air Out. P	IN. H_2O	9.20	9.24	8.92	10.52	10.36	10.41	9.80	10.47
C	PLV 1-A Pri. Air In. Flow	0-125%	126	126	126	124	123	124	126	123
C	PLV 1-B Pri. Air In. Flow	0-125%	130	130	130	125	124	124	130	128
C	PLV 1-C Pri. Air In. Flow	0-125%	132	131	131	131	38	0	130	0
C	PLV 1-D Pri. Air In. Flow	0-125%	0	0	0	123	123	123	0	123
C	PLV 1-E Pri. Air In. Flow	0-125%	127	128	128	127	127	127	128	126
C	PLV 1-F Pri. Air In. Flow	0-125%	125	125	125	128	128	127	125	128
C	PLV 1-A Coal Air Disch. Temp.	°F	144	144	143	148	149	147	143	147

* C - Computer Data; B - Board Data; NA - Not Available.

OVERFIRE AIR OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		17	18	19	20	21	22	23	24
	Date	1976	6/25	6/30	6/29	6/25	6/26	6/25	6/27	6/29
	Time		11:15	08:35	08:50	14:45	10:30	16:25	11:35	01:30
*C	Load	MW	524	526	523	517	419	422	316	322
	TEMPERATURES									
	Air & Gas - °F									
C	Econ. N Gas Out.		750	733	747	756	684	704	601	625
C	Econ. S Gas Out.		*NA	743	748	NA	NA	NA	NA	631
C	1-A PA Fan Disch. Hdr.		96	84	83	101	102	102	102	93
C	1-B PA Fan Disch. Hdr.		NA	NA	NA	NA	NA	NA	NA	NA
C	1-A AH Pri. Air Out.		682	664	678	694	617	651	549	581
C	1-B AH Pri. Air Out.		678	651	672	694	620	660	548	582
	Steam & Water - °F									
C	Boiler Econ. In.		467	467	468	466	444	446	417	421
C	Downcomer 1		675	675	676	675	670	671	665	668
C	Downcomer 2		676	677	678	677	672	672	666	669
C	Downcomer 3		676	677	678	676	672	672	667	669
C	Downcomer 4		680	681	683	680	676	676	667	673
C	Downcomer 5		678	678	680	678	674	673	675	670
C	Blr. SH ATMP 1-A Stm. In.		840	842	840	849	825	858	667	855
C	Blr. SH ATMP 1-B Stm. In.		866	833	842	854	831	859	824	855
C	Blr. S SH Hdr. Out.		992	1011	1007	1005	999	1005	790	1005
C	Blr. N SH Hdr. Out.		1012	1001	1006	1007	1010	1006	982	1009
C	Turbine Throttle		1000	NA	NA	969	681	913	NA	NA
C	Blr. S RH ATMP Stm. Out. A		479	482	481	477	585	457	484	549
C	Blr. N RH ATMP Stm. Out. B		478	481	480	477	585	455	527	548
C	Blr. S RH Hdr. Out. A		976	1004	993	977	974	986	924	969
C	Blr. N RH Hdr. Out. B		1021	996	1013	1008	1011	1012	894	988
C	HP Htr. 1-G1 & 1-G2 Extr. Stm.		620	621	623	609	579	583	527	543
C	HP Htr. 1-F1 FW Out.		177	138	NA	199	271	206	189	83
C	HP Htr. 1-F2 FW Out.		400	400	400	395	379	381	356	359
C	HP Htr. 1-G1 FW Out.		208	191	191	208	207	208	195	192
C	HP Htr. 1-G2 FW Out.		466	467	467	460	443	444	417	420
C	HP Htr. 1-G1 Drain		122	102	198	142	104	137	113	189
C	HP Htr. 1-G2 Drain		374	433	347	370	355	357	332	299
	PULVERIZER DATA									
C	PLV 1-A Bowl Lower P	IN. H_2O	20.3	20.4	20.2	19.8	19.7	18.0	16.8	17.5
C	PLV 1-B Bowl Lower P	IN. H_2O	24.1	24.4	24.9	24.9	23.9	22.1	20.8	21.6
C	PLV 1-C Bowl Lower P	IN. H_2O	0.09	0.09	0.09	0.10	0.11	0.10	0.11	0.09
C	PLV 1-D Bowl Lower P	IN. H_2O	22.0	21.7	21.6	21.5	21.6	19.4	30.3	17.9
C	PLV 1-E Bowl Lower P	IN. H_2O	21.4	22.8	22.5	20.7	21.3	18.9	18.5	18.8
C	PLV 1-F Bowl Lower P	IN. H_2O	20.7	21.1	20.5	19.4	-1.3	17.5	16.6	-1.3
C	PLV 1-A Bowl Diff. P	IN. H_2O	6.83	6.76	6.80	6.75	6.35	6.26	5.80	6.06
C	PLV 1-B Bowl Diff. P	IN. H_2O	7.84	7.84	8.05	8.13	7.71	7.09	6.68	6.87
C	PLV 1-C Bowl Diff. P	IN. H_2O	0.02	0.01	0.03	0.02	0.01	0.02	0.03	0.04
C	PLV 1-D Bowl Diff. P	IN. H_2O	7.30	7.09	7.12	7.28	7.14	6.63	0.05	6.02
C	PLV 1-E Bowl Diff. P	IN. H_2O	7.04	7.40	7.41	6.90	7.00	6.35	6.27	6.29
C	PLV 1-F Bowl Diff. P	IN. H_2O	7.03	6.91	6.87	6.63	0.06	6.08	5.65	0.06
C	PLV 1-A Coal Air Out. P	IN. H_2O	9.23	9.37	9.12	8.85	8.96	7.84	7.49	7.82
C	PLV 1-B Coal Air Out. P	IN. H_2O	12.06	12.28	12.51	12.33	11.88	10.98	10.39	10.90
C	PLV 1-C Coal Air Out. P	IN. H_2O	0.03	0.05	0.09	0.07	0.11	0.09	0.16	0.18
C	PLV 1-D Coal Air Out. P	IN. H_2O	10.72	10.53	10.54	10.15	10.41	9.12	30.17	8.51
C	PLV 1-E Coal Air Out. P	IN. H_2O	10.34	10.98	10.93	9.82	10.36	8.96	8.99	9.10
C	PLV 1-F Coal Air Out. P	IN. H_2O	9.89	10.38	9.99	9.11	-1.33	8.12	7.99	-1.22
C	PLV 1-A Pri. Air In. Flow	0-125%	124	124	124	124	124	127	123	124
C	PLV 1-B Pri. Air In. Flow	0-125%	126	128	128	128	127	127	127	128
C	PLV 1-C Pri. Air In. Flow	0-125%	45	0	0	73	74	81	64	36
C	PLV 1-D Pri. Air In. Flow	0-125%	123	123	124	123	123	123	31	123
C	PLV 1-E Pri. Air In. Flow	0-125%	126	126	126	126	126	126	126	126
C	PLV 1-F Pri. Air In. Flow	0-125%	127	128	128	128	0	127	127	0
C	PLV 1-A Coal Air Disch. Temp.	°F	146	146	152	150	140	150	143	152

* C - Computer Data; B - Board Data; NA - Not Available.

OVERFIRE AIR OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8
	Date	1976	3/17	3/17	3/20	3/20	3/22	3/20	3/20	3/20
	Time		09:30	10:45	16:50	19:45	17:00	10:05	12:00	14:30
*C	Load	MW	517	512	524	525	526	521	522	522
	PULVERIZER DATA									
C	PLV 1-B Coal Air Disch. Temp.	°F	82	87	93	93	88	91	92	93
C	PLV 1-C Coal Air Disch. Temp.	°F	150	148	149	149	142	150	149	149
C	PLV 1-D Coal Air Disch. Temp.	°F	148	148	148	149	147	145	145	146
C	PLV 1-E Coal Air Disch. Temp.	°F	143	142	142	142	142	142	142	142
C	PLV 1-F Coal Air Disch. Temp.	°F	146	146	146	146	146	146	146	147
C	PLV 1-A Feeder Coal Flow	10^3 LB/HR	114	114	116	117	114	115	115	114
C	PLV 1-B Feeder Coal Flow	10^3 LB/HR	0	0	0	0	0	0	0	0
C	PLV 1-C Feeder Coal Flow	10^3 LB/HR	107	106	108	109	113	107	107	107
C	PLV 1-D Feeder Coal Flow	10^3 LB/HR	115	116	117	118	115	116	115	116
C	PLV 1-E Feeder Coal Flow	10^3 LB/HR	116	116	116	118	114	116	116	116
C	PLV 1-F Feeder Coal Flow	10^3 LB/HR	116	116	116	117	115	115	115	115
C	PLV 1-A Mill	AMPS	71	71	73	73	72	72	72	72
C	PLV 1-B Mill	AMPS	0	0	0	0	0	0	0	0
C	PLV 1-C Mill	AMPS	74	74	74	73	78	74	75	74
C	PLV 1-D Mill	AMPS	73	73	76	75	75	76	76	75
C	PLV 1-E Mill	AMPS	75	75	78	77	75	77	76	75
C	PLV 1-F Mill	AMPS	74	75	76	77	76	77	77	75
	FAN DAMPER POSITION - % OPEN									
*B	1-A FD Fan Inlet Vane		71	71	75	74	72	73	72	73
B	1-B FD Fan Inlet Vane		70	70	74	73	71	72	72	72
B	1-A PA Fan Inlet Vane		28	28	33	32	30	34	34	34
B	1-B PA Fan Inlet Vane		24	24	29	28	26	30	30	30
	SPRAY VALVE POSITION - % OPEN									
B	1-A SH Spray Valve		45	37	22	21	62	0	17	12
B	1-B SH Spray Valve		27	25	0	5	30	0	0	0
B	1-A RH Spray Valve		80	84	49	56	60	6	28	33
B	1-B RH Spray Valve		90	96	35	40	43	9	41	46
	MISCELLANEOUS									
B	Burner Tilt	± DEGREES	-3°	-3°	+1°	+3°	0°	+5°	+5°	-1°
B	Aux. Air Dampers	% OPEN	100	100	81	69	68	77	66	58
B	1-A Fuel/Air Dampers	% OPEN	50	50	51	53	50	50	50	50
B	1 B Fuel/Air Dampers	% OPEN	0	0	0	0	0	0	0	0
B	1-C Fuel/Air Dampers	% OPEN	47	46	47	48	51	45	46	46
B	1-D Fuel/Air Dampers	% OPEN	53	53	54	55	53	52	53	53
B	1-E Fuel/Air Dampers	% OPEN	51	51	52	53	51	50	51	51
B	1-F Fuel/Air Dampers	% OPEN	51	51	51	52	51	50	50	50
B	1-A Pri. Air Fan	AMPS	172	172	170	170	171	170	170	169
B	1-B Pri. Air Fan	AMPS	183	183	182	181	182	180	182	181
B	1-A ID Fan	AMPS	500	500	500	500	490	470	460	470
B	1-B ID Fan	AMPS	430	430	430	420	420	400	400	400
B	1-A FD Fan	AMPS	208	207	203	200	202	195	194	192
B	1-B FD Fan	AMPS	195	195	193	190	190	183	184	182
B	1-A ID Fan	RPM	485	485	490	490	480	480	483	480
B	1-B ID Fan	RPM	495	495	500	500	495	490	490	490
B	1-A Blr. Circ. Wtr. Pump	AMPS	74	74	76	76	75	80	77	77
B	1-B Blr. Circ. Wtr. Pump	AMPS	77	77	78	78	78	80	79	79
B	1-C Blr. Circ. Wtr. Pump	AMPS	72	72	74	72	73	76	75	74
B	1-D Blr. Circ. Wtr. Pump	AMPS	74	74	74	74	74	78	76	76
C	N Drum Level ± Norm. H_2O Level	IN.	-0.69	-0.62	-0.69	-0.53	-0.68	-0.48	-0.58	-0.44
C	S Drum Level ± Norm. H_2O Level	IN.	-2.25	-2.27	-2.22	-2.75	-2.97	-2.28	-2.61	-2.64
C	Flue Gas Combustibles	%	0.065	0.066	0.061	0.061	0.063	0.063	0.064	0.064
C	Flue Gas Oxygen	%	4.0	3.9	4.0	3.9	4.0	3.6	3.4	3.6
C	Baronmetric Press.	IN. HGA	30.04	29.99	28.80	28.89	30.29	28.64	28.72	28.72

* C - Computer Data; B - Board Data; NA - Not Available.

OVERFIRE AIR OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		9	10	11	12	13	14	15	16
	DATE	1976	3/24	3/24	3/24	6/24	6/24	6/24	3/25	6/30
	TIME		00:45	02:20	04:00	12:00	13:20	09:45	10:15	09:50
*C	LOAD	MW	473	473	472	524	525	523	510	526
	PULVERIZER DATA									
C	PLV 1-B COAL AIR DISCH. TEMP.	°F	146	144	143	154	155	153	142	156
C	PLV 1-C COAL AIR DISCH. TEMP.	°F	149	148	148	0	0	0	148	0
C	PLV 1-D COAL AIR DISCH. TEMP.	°F	155	152	149	147	148	146	86	145
C	PLV 1-E COAL AIR DISCH. TEMP.	°F	142	141	140	142	143	143	140	156
C	PLV 1-F COAL AIR DISCH. TEMP.	°F	146	146	144	149	149	148	144	148
C	PLV 1-A FEEDER COAL FLOW	10^3 LB/HR	102	101	102	118	118	118	110	117
C	PLV 1-B FEEDER COAL FLOW	10^3 LB/HR	105	105	105	119	120	119	114	118
C	PLV 1-C FEEDER COAL FLOW	10^3 LB/HR	102	102	103	0	0	0	111	0
C	PLV 1-D FEEDER COAL FLOW	10^3 LB/HR	0	0	0	118	118	118	0	117
C	PLV 1-E FEEDER COAL FLOW	10^3 LB/HR	104	104	104	118	118	117	112	115
C	PLV 1-F FEEDER COAL FLOW	10^3 LB/HR	103	102	102	117	118	116	112	117
C	PLV 1-A MILL	AMPS	66	67	66	72	73	71	73	71
C	PLV 1-B MILL	AMPS	72	72	72	74	74	74	73	73
C	PLV 1-C MILL	AMPS	72	71	71	0	0	0	73	0
C	PLV 1-D MILL	AMPS	0	0	0	72	72	72	0	72
C	PLV 1-E MILL	AMPS	71	70	69	75	75	74	75	73
C	PLV 1-F MILL	AMPS	73	71	71	74	75	74	76	74
	FAN DAMPER POSITION - % OPEN									
*B	1-A FD FAN INLET VANE		76	75	73	80	81	80	72	77
B	1-B FD FAN INLET VANE		76	75	73	83	83	83	70	80
B	1-A PA FAN INLET VANE		30	30	30	31	31	30	29	30
B	1-B PA FAN INLET VANE		26	25	25	30	30	30	25	30
	SPRAY VALVE POSITION - % OPEN									
B	1-A SH SPRAY VALVE		44	46	70	25	29	25	34	28
B	1-B SH SPRAY VALVE		32	31	39	61	62	62	26	35
B	1-A RH SPRAY VALVE		39	37	46	47	65	36	63	41
B	1-B RH SPRAY VALVE		41	44	54	34	47	25	74	39
	MISCELLANEOUS									
B	BURNER TILT	± DEGREES	0°	0°	0°	+1°	+7°	+3°	0°	+3°
B	AUX. AIR DAMPERS	% OPEN	41	90	66	100	26	25	60	25
B	1-A FUEL/AIR DAMPERS	% OPEN	42	42	42	100	100	100	47	100
B	1-B FUEL/AIR DAMPERS	% OPEN	44	43	44	0	100	100	49	100
B	1-C FUEL/AIR DAMPERS	% OPEN	43	42	43	100	0	0	49	0
B	1-D FUEL/AIR DAMPERS	% OPEN	0	0	0	100	100	100	0	100
B	1-E FUEL/AIR DAMPERS	% OPEN	44	43	45	100	100	100	49	100
B	1-F FUEL/AIR DAMPERS	% OPEN	43	43	44	100	100	100	49	100
B	1-A PRI. AIR FAN	AMPS	167	170	170	165	165	165	162	165
B	1-B PRI. AIR FAN	AMPS	180	180	180	200	200	202	182	205
B	1-A ID FAN	AMPS	500	500	480	510	520	520	460	490
B	1-B ID FAN	AMPS	430	430	410	470	480	480	400	450
B	1-A FD FAN	AMPS	211	210	203	226	228	229	200	224
B	1-B FD FAN	AMPS	198	195	188	202	205	205	185	204
B	1-A ID FAN	RPM	493	494	490	*NA	NA	NA	487	490
B	1-B ID FAN	RPM	499	498	495	NA	NA	NA	492	NA
B	1-A BLR. CIRC. WTR. PUMP	AMPS	76	76	75	74	73	75	76	77
B	1-B BLR. CIRC. WTR. PUMP	AMPS	78	78	78	80	80	81	78	82
B	1-C BLR. CIRC. WTR. PUMP	AMPS	73	72	73	73	73	75	72	75
B	1-D BLR. CIRC. WTR. PUMP	AMPS	75	74	74	75	74	76	74	78
C	N DRUM LEVEL ± NORM. H_2O LEVEL	IN.	-0.72	-0.49	-0.66	-0.35	-0.54	-0.74	-0.48	-0.35
C	S DRUM LEVEL ± NORM. H_2O LEVEL	IN.	-2.24	-1.96	-2.50	-2.60	-2.45	-1.83	-2.64	-0.70
C	FLUE GAS COMBUSTIBLES	%	0.060	0.060	0.057	0.056	0.055	0.054	0.063	0.056
C	FLUE GAS OXYGEN	%	4.7	5.1	4.6	3.2	3.9	3.7	3.6	4.3
C	BARONMETRIC PRESS.	IN. HGA	29.53	29.49	29.43	29.52	29.45	29.59	29.81	29.85

* C - COMPUTER DATA; B - BOARD DATA; NA - NOT AVAILABLE.

OVERFIRE AIR OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		17	18	19	20	21	22	23	24
	Date	1976	6/25	6/30	6/29	6/25	6/26	6/25	6/27	6/29
	Time		11:15	08:35	08:50	14:45	10:30	16:25	11:35	01:30
*C	Load	MW	524	526	523	517	419	422	316	322
	PULVERIZER DATA									
C	PLV 1-B Coal Air Disch. Temp.	°F	153	154	158	156	147	161	150	156
C	PLV 1-C Coal Air Disch. Temp.	°F	0	0	0	0	0	0	0	0
C	PLV 1-D Coal Air Disch. Temp.	°F	146	144	150	150	141	151	111	148
C	PLV 1-E Coal Air Disch. Temp.	°F	142	154	159	142	143	142	147	158
C	PLV 1-F Coal Air Disch. Temp.	°F	147	143	150	150	114	152	142	111
C	PLV 1-A Feeder Coal Flow	10^3 LB/HR	117	118	113	115	116	90	84	83
C	PLV 1-B Feeder Coal Flow	10^3 LB/HR	118	119	116	116	117	92	86	86
C	PLV 1-C Feeder Coal Flow	10^3 LB/HR	0	0	0	0	0	0	0	0
C	PLV 1-D Feeder Coal Flow	10^3 LB/HR	117	118	114	115	115	91	0	84
C	PLV 1-E Feeder Coal Flow	10^3 LB/HR	117	115	114	114	115	92	86	84
C	PLV 1-F Feeder Coal Flow	10^3 LB/HR	116	117	113	114	0	90	84	0
C	PLV 1-A Mill	AMPS	73	71	70	72	74	63	64	63
C	PLV 1-B Mill	AMPS	75	73	74	76	75	69	67	67
C	PLV 1-C Mill	AMPS	0	0	0	0	0	0	0	0
C	PLV 1-D Mill	AMPS	73	74	73	72	74	68	0	64
C	PLV 1-E Mill	AMPS	75	71	70	76	75	68	66	65
C	PLV 1-F Mill	AMPS	76	75	73	75	0	69	67	0
	FAN DAMPER POSITION - % OPEN									
*B	1-A FD Fan Inlet Vane		80	78	76	81	73	70	59	58
B	1-B FD Fan Inlet Vane		83	81	79	83	76	73	62	61
B	1-A PA Fan Inlet Vane		31	30	30	31	28	33	28	28
B	1-B PA Fan Inlet Vane		30	29	29	31	28	33	28	27
	SPRAY VALVE POSITION - % OPEN									
B	1-A SH Spray Valve		89	28	28	49	19	29	0	26
B	1-B SH Spray Valve		59	35	33	50	15	33	0	26
B	1-A RH Spray Valve		53	36	48	69	0	25	0	0
B	1-B RH Spray Valve		41	30	40	50	0	17	0	0
	MISCELLANEOUS									
B	Burner Tilt	± DEGREES	+8°	+3°	+6°	+6°	+6°	+3°	+11°	+8°
B	Aux. Air Dampers	% OPEN	26	25	19	23	14	3	0	0
B	1-A Fuel/Air Dampers	% OPEN	100	100	100	100	100	94	80	77
B	1-B Fuel/Air Dampers	% OPEN	100	100	100	100	100	92	80	77
B	1-C Fuel/Air Dampers	% OPEN	0	0	0	0	0	0	0	0
B	1-D Fuel/Air Dampers	% OPEN	100	100	100	100	100	89	0	74
B	1-E Fuel/Air Dampers	% OPEN	100	100	100	100	100	89	77	75
B	1-F Fuel/Air Dampers	% OPEN	100	100	100	100	0	90	77	0
B	1-A Pri. Air Fan	AMPS	165	165	165	165	155	165	160	155
B	1-B Pri. Air Fan	AMPS	200	203	200	200	190	200	195	195
B	1-A ID Fan	AMPS	520	500	470	510	390	380	300	290
B	1-B ID Fan	AMPS	470	450	420	470	340	340	280	260
B	1-A FD Fan	AMPS	165	225	214	222	200	185	165	165
B	1-B FD Fan	AMPS	200	205	193	200	180	170	150	147
B	1-A ID Fan	RPM	*NA	490	480	500	450	450	330	325
B	1-B ID Fan	RPM	NA	NA	NA	NA	NA	NA	NA	NA
B	1-A Blr. Circ. Wtr. Pump	AMPS	74	77	75	75	78	75	83	80
B	1-B Blr. Circ. Wtr. Pump	AMPS	79	82	80	80	84	82	87	85
B	1-C Blr. Circ. Wtr. Pump	AMPS	73	74	73	73	78	75	0	77
B	1-D Blr. Circ. Wtr. Pump	AMPS	74	80	75	76	81	78	85	84
C	N Drum Level ± Norm. H_2O Level	IN.	-0.77	-0.87	-0.44	-0.72	-0.52	-0.53	-0.59	-0.56
C	S Drum Level ± Norm. H_2O Level	IN.	-2.99	-0.89	-2.19	-1.40	-1.39	-1.30	-2.03	-1.42
C	Flue Gas Combustibles	%	0.056	0.056	0.055	0.056	0.055	0.055	0.053	0.048
C	Flue Gas Oxygen	%	3.4	4.4	3.5	4.3	4.6	4.3	5.8	4.7
C	Baronmetric Press.	IN. HGA	29.65	29.86	29.75	29.65	29.89	29.63	30.12	29.76

* C - Computer Data; B - Board Data; NA - Not Available.

WATERWALL CORROSION COUPON DATA SUMMARY

WEIGHT LOSS EVALUATION

BASELINE TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. g	Final Wt. g	Wt. Loss g	Wt. Loss/ Coupon mg/cm^2	Avg. Wt. Loss/ Probe mg/cm^2
1	A	11	192.4714	191.6956	.7758	15.3814	11.2471
		12	189.2624	188.5251	.7373	14.6180	
		13	187.7834	187.3753	.4081	8.0912	
		14	189.5986	189.1607	.3479	6.8976	
2	B	11	191.8667	191.3217	.5450	10.8054	7.9955
		12	193.0534	192.5138	.5396	10.6983	
		13	192.4719	192.1794	.2925	5.7992	
		14	187.2771	187.0411	.2360	4.6790	
3	C	11	189.6148	189.1926	.4222	8.3707	7.7150
		12	192.3205	191.8693	.4512	8.9457	
		13	194.2087	193.8685	.3402	6.7450	
		14	195.2487	194.9058	.3429	6.7985	
4	D	11	181.0037	180.7035	.3002	5.9519	5.5544
		12	196.4728	196.1221	.3407	6.7549	
		13	192.6319	192.3687	.2632	5.2183	
		14	189.7795	189.5630	.2165	4.2924	
5	E	11	191.8554	191.4543	.4011	7.9524	7.8731
		12	194.4597	193.9813	.4784	9.4850	
		13	191.4211	191.0273	.3938	7.8077	
		14	196.5282	196.2131	.3151	6.2473	

Avg. Wt. Loss/Test 8.0770 mg/cm^2

WATERWALL CORROSION COUPON DATA SUMMARY

WEIGHT LOSS EVALUATION

OVERFIRE AIR TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. g	Final Wt. g	Wt. Loss g	Wt. Loss/ Coupon mg/cm^2	Avg. Wt. Loss/ Probe mg/cm^2
1	G	11	194.9117	194.5574	.3543	7.0245	
		12	190.1947	189.8822	.3125	6.1957	8.4445
		13	196.6078	196.2830	.3248	6.4396	
		14	196.0734	195.3612	.7121	14.1182	
2	H	11	186.5016	186.0373	.4643	9.2053	
		12	190.5570	190.0113	.5457	10.8191	9.9423
		13	195.0431	194.5049	.5382	10.6704	
		14	191.5820	191.1243	.4577	9.0744	
3	I	11	192.8761	192.2601	.6160	12.2129	
		12	197.6064	197.1149	.4915	9.7445	9.2479
		13	194.6839	194.3220	.3619	7.1751	
		14	194.3763	193.9799	.3964	7.8591	
4	J	11	189.5101	189.1223	.3878	7.6886	
		12	191.3316	190.9150	.4166	8.2596	7.2544
		13	189.2178	188.8155	.4023	7.9760	
		14	188.7732	188.5163	.2569	5.0933	
5	K	11	193.0880	192.7809	.3071	6.0886	
		12	187.8881	187.5455	.3426	6.7924	5.5776
		13	186.7728	186.5222	.2506	4.9684	
		14	189.5299	189.3049	.2250	4.4609	

Avg. Wt. Loss/Test 8.0933 mg/cm^2

APPENDIX B

TEST DATA & RESULTS
FOR
UTAH POWER & LIGHT COMPANY
HUNTINGTON CANYON STATION
UNIT #2

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BASELINE OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		1	2	2A	3	4	5	6	7	8	9
PURPOSE OF TEST		← EXCESS AIR VARIATION →									
UNIT LOAD CONDITION		MAX	MAX	MAX	MAX	3/4 MAX	1/2 MAX	1/2 MAX	1/2 MAX	MAX	MAX
FURNACE CONDITION		CLEAN	CLEAN	CLEAN	CLEAN	CLEAN	CLEAN	CLEAN	CLEAN	CLEAN	CLEAN
DATE	1975	5/7	5/5	5/7	5/7	10/10	7/16	7/15	7/16	5/5	4/30
UNIT LOAD	MW	429	427	428	428	360	259	260	258	430	428
MAIN STEAM FLOW	KG/S	376	380	377	380	298	204	203	202	378	377
SHO TEMPERATURE	C	531	541	534	536	547	546	543	544	541	534
RHO TEMPERATURE	C	538	547	537	537	548	529	538	537	543	537
FUEL ELEVATIONS IN SERVICE		ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ABCD	ABCD	ABCD	ALL 5	ALL 5
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0	0	0
FUEL NOZZLE TILT	DEG	+14	+11	+13	+15	0	+18	+11	+6	+8	-3
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN: [ ] OFA		0	0	0	0	0	0	0	0	0	0
[ ] OFA		0	0	0	0	0	0	0	0	0	0
[ ] AUX		45	45	45	45	15	0	0	0	30	40
[A] FUEL		100	100	100	100	100	100	100	100	100	100
[ ] AUX		50	50	45	45	10	0	0	0	40	45
[B] FUEL		100	100	100	100	100	100	100	100	100	100
[ ] AUX		45	45	45	45	5	0	0	0	20	35
[C] FUEL		100	100	100	100	100	100	100	100	100	100
[ ] AUX		50	50	50	45	0	0	0	0	35	35
[D] FUEL		100	100	100	100	100	100	100	100	100	100
[ ] AUX		50	50	50	50	0	0	0	0	40	40
[E] FUEL		100	100	100	100	100	0	0	0	100	100
[ ] AUX		100	100	100	100	100	35	0	0	100	100
EXCESS AIR AT ECONOMIZER OUTLET	%	18.9	27.4	32.9	40.9	28.9	23.7	32.1	50.0	19.5	29.0
THEO. AIR TO THE FUEL FIRING ZONE	%	116.4	124.8	130.1	137.8	126.9	122.9	131.1	150.0	117.5	126.3
NO_x (ADJ. TO 0% O_2)	PPM	476	533	670	718	662	509	573	734	535	522
NO_x AS NO_2	NG/J	248.0	262.8	332.4	357.0	328.0	249.2	284.3	360.3	267.1	256.6
SO_2 (ADJ. TO 0% O_2)	PPM	NA	388	396	374	436	376	363	326	364	237
SO_2	NG/J	0	266.3	273.2	259.1	300.1	256.2	250.5	222.8	252.5	163.4
CO (ADJ. TO 0% O_2)	PPM	NA	23	25	27	NA	16	16	17	23	124
CO	NG/J	0	6.9	7.7	8.2	0	4.8	4.8	5.0	6.9	37.5
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	3.4	4.6	5.3	6.2	4.8	4.1	5.2	7.1	3.5	4.8
O_2 AT A.H. OUTLET	%	4.5	5.8	6.4	7.3	7.3	6.1	6.2	8.6	5.4	6.1
CO_2 AT ECONOMIZER OUTLET	%	15.4	14.1	13.5	12.8	14.0	14.7	13.6	12.1	15.1	14.2
CO_2 AT A.H. OUTLET	%	14.4	13.1	12.6	11.9	11.8	13.0	12.8	10.8	13.4	13.0
CARBON LOSS IN FLYASH	%	0.52	0.37	0.22	0.31	0.12	0.23	0.30	0.12	0.68	0.29

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BASELINE OPERATION STUDY

EMISSIONS TEST DATA

Test No.		10	11	12	13	14	15	16	17	18	19
Purpose of Test		← Excess Air Variation →									
Unit Load Condition		Max	1/2 Max	1/2 Max	Max	Max	Max	3/4 Max	1/2 Max	1/2 Max	1/2 Max
Furnace Condition		← Clean →			← Moderately Dirty →						
Date	1975	5/1	7/17	7/18	5/9	5/9	5/9	10/9	7/22	7/21	7/21
Unit Load	MW	428	256	259	433	433	433	361	258	260	258
Main Steam Flow	kg/s	375	203	208	377	375	375	298	204	206	205
SHO Temperature	C	545	543	543	532	536	539	548	541	541	542
RHO Temperature	C	546	536	534	538	538	540	545	528	536	536
Fuel Elevations in Service		All 5	ABCD	ABCD	All 5	All 5	All 5	All 5	ACDE	ACDE	ACDE
OFA Nozzle Tilt	Deg	0	0	0	0	0	0	0	0	0	0
Fuel Nozzle Tilt	Deg	+7	+6	+3	+3	+8	+1	0	+12	+13	+13
Nozzle Compartment Damper Position - % Open: OFA		0	0	0	0	0	0	0	0	0	0
OFA		0	0	0	0	0	0	0	0	0	0
AUX		45	0	0	30	35	45	15	0	0	0
A FUEL		100	100	100	100	100	100	100	100	100	100
AUX		45	0	0	45	45	50	15	0	0	0
B FUEL		100	100	100	100	100	100	100	0	0	0
AUX		40	0	0	25	30	35	5	0	0	0
C FUEL		100	100	100	100	100	100	100	100	100	100
AUX		40	0	0	35	45	50	10	0	0	0
D FUEL		100	100	100	100	100	100	20	100	100	100
AUX		50	0	0	40	45	50	20	0	0	0
E FUEL		100	0	0	100	100	100	100	100	100	100
AUX		100	0	0	100	100	100	100	0	0	0
Excess Air at Economizer Outlet	%	40.9	27.4	48.8	15.0	20.2	35.5	23.0	25.2	28.9	47.8
Theo. Air to the Fuel Firing Zone	%	137.8	126.4	147.6	113.1	118.1	132.6	121.3	124.3	127.9	146.6
NO_x (Adj. to 0% O_2)	PPM	594	474	645	433	514	644	592	438	470	669
NO_x as NO_2	ng/J	295.3	232.6	318.8	213.8	253.7	319.1	285.2	215.7	233.0	333.1
SO_2 (Adj. to 0% O_2)	PPM	271	236	332	258	372	355	405	446	448	474
SO_2	ng/J	187.3	160.9	228.0	177.7	255.2	245.2	281.1	306.1	309.0	328.2
CO (Adj. to 0% O_2)	PPM	NA	15	16	35	24	27	14	15	NA	16
CO	ng/J	0	4.6	5.0	10.4	7.2	8.3	4.1	4.5	0	5.0
HC (Adj. to 0% O_2)	PPM	0	0	0	0	0	0	0	0	0	0
O_2 at Economizer Outlet	%	6.2	4.6	7.0	2.8	3.6	5.6	4.0	4.3	4.8	6.9
O_2 at A.H. Outlet	%	7.6	5.7	8.1	4.4	5.0	6.6	5.9	6.0	6.9	8.1
CO_2 at Economizer Outlet	%	12.8	14.3	12.1	15.8	15.1	13.4	14.7	14.5	14.0	12.2
CO_2 at A.H. Outlet	%	11.6	13.3	11.1	14.4	13.9	12.5	13.1	13.1	12.1	11.1
Carbon Loss in Flyash	%	0.23	0.24	0.13	0.53	0.50	0.15	0.09	0.21	0.26	0.17

BIASED FIRING OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		1	2	3	4	5	6	7	8
		← VARIATION OF FUEL ELEVATIONS IN SERVICE →							
		← MAXIMUM →			← 3/4 MAXIMUM →			1/2 MAXIMUM →	
		← MINIMUM →							
PURPOSE OF TEST		CLEAN	MODERATE	CLEAN	CLEAN	MODERATE	CLEAN	CLEAN	MODERATE
UNIT LOAD CONDITION		9/17	9/18	9/20	12/13	10/11	10/12	10/12	10/5
EXCESS AIR CONDITION		430	426	434	356	351	360	257	270
FURNACE CONDITION	1975								
DATE	MW	375	371	368	297	295	299	218	214
UNIT LOAD	KG/S	518	525	534	544	536	543	542	543
MAIN STEAM FLOW	C	536	541	541	539	537	546	534	544
SHO TEMPERATURE	C	BCDE	ABDE	ABCD	BCDE	ACDE	ABCE	BCDE	ABDE
RHO TEMPERATURE	DEG	0	0	0	0	0	0	0	0
FUEL ELEVATIONS IN SERVICE	DEG	+6	-6	-13	+18	-10	-9	+6	-9
OFA NOZZLE TILT									
FUEL NOZZLE TILT									
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN									
OFA		0	0	0	0	0	0	0	0
OFA		0	0	0	0	0	0	0	0
AUX		20	30	50	10	0	5	5	10
A FUEL		10	100	100	100	100	100	100	100
AUX		30	40	50	0	25	0	0	5
B FUEL		100	100	100	100	100	100	100	100
AUX		10	10	45	0	5	0	5	5
C FUEL		100	0	100	100	100	100	100	100
AUX		25	25	50	0	0	0	0	0
D FUEL		100	100	100	100	100	100	100	0
AUX		20	25	50	0	0	0	100	100
E FUEL		100	100	20	100	100	100	100	100
AUX		100	100	20	100	100	100	100	100
EXCESS AIR AT ECONOMIZER OUTLET	%	19.8	21.5	20.9	16.8	19.9	20.8	22.6	24.4
THEO. AIR TO THE FUEL FIRING ZONE	%	107.1	118.9	117.8	98.5	119.3	119.8	106.5	122.8
NO_x (ADJ. TO 0% O_2)	PPM	340	449	490	367	404	530	363	534
NO_x AS NO_2	NG/J	168.4	223.7	243.1	191.5	203.6	263.4	178.4	263.3
SO_2 (ADJ. TO 0% O_2)	PPM	418	358	387	257	375	359	259	360
SO_2	NG/J	287.5	247.8	267.1	186.4	262.9	248.2	245.7	247.1
CO (ADJ. TO 0% O_2)	PPM	56	16	30	20	14	16	16	14
CO	NG/J	16.7	4.8	9.2	6.3	4.4	4.8	4.8	4.1
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	3.6	3.8	3.7	3.1	3.6	3.7	4.0	4.2
O_2 AT A.H. OUTLET	%	5.7	4.4	5.7	5.6	5.8	5.5	5.8	5.9
CO AT ECONOMIZER OUTLET	%	15.1	14.9	15.0	15.3	15.2	14.9	14.8	14.5
CO_2 AT A.H. OUTLET	%	13.2	14.3	13.2	13.1	13.2	13.4	13.2	13.1
CARBON LOSS IN FLYASH	%	0.26	0.25	0.55	0.61	0.20	0.22	0.46	0.22

BIASED FIRING OPERATION STUDY

EMISSIONS TEST DATA

VARIATION OF FUEL ELEVATIONS IN SERVICE

TEST NO.		9	10	11	12	13	14	15	16
		← MAXIMUM →			← 3/4 MAXIMUM →			1/2 MAXIMUM →	
PURPOSE OF TEST		← NORMAL →							
UNIT LOAD CONDITION		CLEAN	CLEAN	MODERATE	MODERATE	CLEAN	CLEAN	CLEAN	CLEAN
EXCESS AIR CONDITION		9/17	9/18	9/18	10/11	12/13	12/13	7/23	7/24
FURNACE CONDITION	1975	429	428	429	351	356	357	256	259
DATE	MW	375	370	369	295	299	299	203	210
UNIT LOAD	KG/S	516	536	533	537	543	544	543	542
MAIN STEAM FLOW	C	525	537	541	538	541	541	533	535
SHO TEMPERATURE	C	BCDE	ACDE	ABCE	BCDE	ABDE	ABCD	ACDE	ABCE
RHO TEMPERATURE		0	0	0	0	0	0	0	0
FUEL ELEVATIONS IN SERVICE	DEG	+20	+8	+2	+7	+9	-8	+12	+11
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0
FUEL NOZZLE TILT		0	0	0	0	0	0	0	0
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN: OFA		35	25	30	10	5	100	100	100
OFA		20	100	100	100	100	5	0	0
AUX		50	35	40	5	10	100	100	100
A FUEL		100	25	100	100	100	0	0	0
AUX		15	15	20	5	0	100	100	100
B FUEL		100	100	100	100	100	5	0	0
AUX		20	40	40	5	0	100	100	100
C FUEL		100	100	5	100	100	10	0	0
AUX		35	40	40	5	10	10	100	100
D FUEL		100	100	100	100	100	100	100	100
AUX		100	100	100	100	100	100		
E FUEL									
AUX									
EXCESS AIR AT ECONOMIZER OUTLET	%	26.3	27.4	29.3	29.3	28.0	31.7	25.1	24.7
THEO. AIR TO THE FUEL FIRING ZONE	%	107.6	125.3	126.8	109.1	127.0	131.0	124.4	124.0
NO_x (ADJ. TO 0% O_2)	PPM	421	462	513	421	549	502	382	453
NO_x AS NO_2	NG/J	208.1	227.3	255.9	214.2	283.8	248.4	187.2	224.3
SO_2 (ADJ. TO 0% O_2)	PPM	408	382	389	406	291	252	429	443
	NG/J	280.8	261.1	269.9	286.9	209.5	173.7	292.2	305.1
CO (ADJ. TO 0% O_2)	PPM	17	17	17	17	18	21	15	15
	NG/J	5.0	5.0	5.2	5.2	5.7	6.4	4.5	4.6
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	4.5	4.6	4.9	4.9	4.7	5.2	4.3	4.3
O_2 AT A.H. OUTLET	%	6.1	6.9	5.2	6.3	7.0	7.1	6.1	5.9
CO_2 AT ECONOMIZER OUTLET	%	14.4	14.4	14.0	14.0	13.9	13.7	14.4	14.4
CO_2 AT A.H. OUTLET	%	13.0	12.4	13.7	12.7	11.9	12.0	12.9	13.0
CARBON LOSS IN FLYASH	%	0.28	0.24	0.18	0.22	0.38	0.41	0.12	0.20

OVERFIRE AIR OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12
		OVERFIRE AIR VARIATION →											TILT VAR WITH OFA →
PURPOSE OF TEST		← MAXIMUM →						← MINIMUM →		← MAXIMUM →			MIN
UNIT LOAD CONDITION		← NORMAL →								CLEAN	CLEAN	MODERATE	MODERATE
EXCESS AIR CONDITION		← MODERATE →											
FURNACE CONDITION		HEAVY	HEAVY	HEAVY									
DATE	1975	9/17	9/26	9/26	9/26	9/26	10/1	10/1	10/1	9/27	10/1	10/1	10/5
UNIT LOAD	MW	428	430	430	430	431	430	429	428	428	429	430	427
MAIN STEAM FLOW	KG/S	369	372	372	370	370	372	372	370	369	368	370	370
SHO TEMPERATURE	C	532	529	530	533	532	534	528	531	528	535	535	526
RHO TEMPERATURE	C	539	539	538	537	536	547	541	543	540	540	540	540
FUEL ELEVATIONS IN SERVICE		ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0	0	0	0	-30
FUEL NOZZLE TILT	DEG	+6	-10	-10	-14	-12	+10	+10	+10	+8	+17	+13	-20
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN: OFA		0	25	50	75	100	0	50	100	25	75	100	100
OFA		0	25	50	75	100	0	50	100	25	75	100	100
AUX		20	25	20	15	15	20	15	15	45	15	15	15
A FUEL		100	100	100	100	100	100	100	100	100	100	100	100
AUX		35	40	30	20	20	20	10	0	45	25	20	0
B FUEL		100	100	100	100	100	100	100	100	100	100	100	100
AUX		15	20	10	15	5	10	5	5	35	10	5	5
C FUEL		100	100	100	100	100	100	100	100	100	100	100	100
AUX		35	30	20	20	20	20	10	0	35	15	20	0
D FUEL		100	100	100	100	100	100	100	100	100	100	100	100
AUX		20	40	30	20	20	20	0	0	30	25	25	0
E FUEL		100	100	100	100	100	100	100	100	100	100	100	100
AUX		100	100	100	100	100	100	100	100	100	100	100	100
EXCESS AIR AT ECONOMIZER OUTLET	%	27.0	28.2	26.2	25.5	25.2	18.5	19.2	19.2	32.1	33.8	33.8	23.1
THEO. AIR TO THE FUEL FIRING ZONE	%	125.2	120.2	111.6	107.1	105.4	116.7	102.9	96.6	123.2	113.8	112.5	99.6
NO_x (ADJ. TO 0% O_2)	PPM	543	513	462	430	417	604	492	446	711	677	673	452
NO_x AS NO_2	NG/J	273.7	251.1	229.4	213.0	205.3	300.1	247.3	221.6	353.2	334.0	332.3	223.3
SO_2 (ADJ. TO 0% O_2)	PPM	370	452	370	402	416	373	385	538	476	361	421	427
SO_2	NG/J	259.6	308.2	255.8	277.2	284.8	258.2	269.4	371.4	328.9	247.6	289.4	293.7
CO (ADJ. TO 0% O_2)	PPM	15	15	15	15	15	16	119	162	16	15	16	34
CO	NG/J	4.7	4.6	4.6	4.6	4.5	4.7	36.3	49.0	4.8	4.4	4.8	10.4
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	4.6	4.7	4.5	4.4	4.3	3.4	3.5	3.5	5.2	5.4	5.4	4.0
O_2 AT A.H. OUTLET	%	6.8	5.1	5.3	5.6	5.3	4.8	4.9	4.7	7.0	7.8	7.1	4.8
CO_2 AT ECONOMIZER OUTLET	%	14.2	14.2	14.3	14.5	14.5	15.2	15.1	15.2	13.7	13.5	13.5	14.8
CO_2 AT A.H. OUTLET	%	12.3	13.8	13.5	13.4	13.7	13.9	13.8	14.1	12.1	11.4	12.0	14.1
CARBON LOSS IN FLYASH	%	0.20	0.14	0.24	0.30	0.28	0.24	0.59	0.24	0.22	0.27	0.16	0.25

OVERFIRE AIR OPERATION STUDY

EMISSIONS TEST DATA

TEST NO.		13	14	15	16	17	18	19	20	21	22	23	24
PURPOSE OF TEST		← TILT VARIATION WITH OFA →						← OPTIMUM OFA OPERATION →					
UNIT LOAD CONDITION		← MAXIMUM →									3/4 MAX	3/4 MAX	1/2 MAX	1/2 MAX
EXCESS AIR CONDITION		← MINIMUM →											
FURNACE CONDITION		MODERATE	MODERATE	HEAVY	MODERATE	MODERATE	MODERATE	CLEAN	MODERATE	CLEAN	MODERATE	CLEAN	MODERATE
DATE	1975	10/4	10/5	10/4	10/3	10/3	10/3	10/6	10/8	10/9	10/9	10/12	10/5
UNIT LOAD	MW	434	422	429	427	424	429	417	426	356	358	253	265
MAIN STEAM FLOW	KG/S	364	370	370	372	377	367	374	377	299	299	218	217
SHO TEMPERATURE	C	543	520	531	529	519	535	522	521	531	538	525	542
RHO TEMPERATURE	C	547	525	543	533	515	539	538	527	527	537	510	526
FUEL ELEVATIONS IN SERVICE		ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ALL 5	ABCE	BCDE	ACDE
OFA NOTTLE TILT	DEG	-30	0	0	0	+30	+30	+30	+30	+30	+30	+30	+30
FUEL NOZZLE TILT	DEG	0	-20	0	+25	0	+25	0	0	0	0	0	0
NOZZLE COMPARTMENT DAMPER POSITION - % OPEN: OFA		100	100	100	100	100	100	100	100	100	100	80	75
OFA		100	100	100	100	100	100	100	100	100	100	80	75
AUX		15	0	20	15	15	15	15	15	15	15	10	10
A FUEL		100	100	100	100	100	100	100	100	100	100	0	100
AUX		0	0	0	5	0	5	0	0	0	0	0	0
B FUEL		100	100	100	100	100	100	100	100	100	100	100	0
AUX		0	0	5	5	5	5	0	5	5	5	5	0
C FUEL		100	100	100	100	100	100	100	100	100	100	100	100
AUX		5	0	5	0	0	0	0	5	0	0	0	0
D FUEL		100	100	100	100	100	100	100	100	100	0	100	100
AUX		0	0	0	0	0	0	0	0	0	0	0	0
E FUEL		100	100	100	100	100	100	100	100	100	100	100	100
AUX		100	100	100	100	100	100	100	100	100	100	100	100
EXCESS AIR AT ECONOMIZER OUTLET	%	25.1	22.0	25.1	21.3	23.5	21.7	18.5	19.6	19.3	21.5	22.8	23.9
THEO. AIR TO THE FUEL FIRING ZONE	%	101.1	99.2	101.1	98.4	99.8	98.6	95.8	97.1	98.1	95.0	97.3	99.7
NO_x (ADJ. TO 0% O_2)	PPM	533	366	422	569	375	498	392	382	329	337	266	310
NO_x AS NO_2	NG/J	263.4	179.8	212.1	283.5	186.1	252.1	196.5	190.2	161.3	167.8	132.0	155.3
SO_2 (ADJ. TO 0% O_2)	PPM	450	397	404	386	432	349	347	364	403	358	403	447
SO_2	NG/J	309.4	271.1	281.9	267.5	298.3	245.7	241.8	252.1	275.2	247.8	278.4	311.1
CO (ADJ. TO 0% O_2)	PPM	15	16	15	15	16	51	19	19	19	21	63	15
CO	NG/J	4.5	4.8	4.6	4.4	4.9	15.8	5.8	5.8	5.7	6.3	19.0	4.5
HC (ADJ. TO 0% O_2)	PPM	0	0	0	0	0	0	0	0	0	0	0	0
O_2 AT ECONOMIZER OUTLET	%	4.3	3.9	4.3	3.8	4.1	3.8	3.4	3.5	3.5	3.8	4.0	4.1
O_2 AT A.H. OUTLET	%	5.7	4.9	5.2	5.1	5.4	5.1	5.3	5.6	6.1	5.8	5.5	5.7
CO_2 AT ECONOMIZER OUTLET	%	14.4	14.9	14.5	14.9	14.6	14.9	15.2	15.1	15.3	14.8	14.7	14.6
CO_2 AT A.H. OUTLET	%	13.1	14.0	13.8	13.7	13.5	13.8	13.5	13.3	13.0	13.1	13.3	13.2
CARBON LOSS IN FLYASH	%	0.21	0.30	0.28	0.26	0.22	0.63	0.40	0.43	0.20	0.22	0.47	0.22

BASELINE OPERATION STUDY

TEST DATA

TEST NO.		1	2	2A	3	4	5	6	7	8	9
DATE	1975	5/7	5/5	5/7	5/7	10/10	7/16	7/15	7/16	5/5	4/30
UNIT LOAD	MW	429	427	428	428	360	259	260	258	430	428
FLOWS	KG/SEC										
FEEDWATER		375	375	377	377	295	201	198	195	375	377
1ST STAGE STEAM		372	372	374	373	282	186	186	185	373	369
PRESSURES	MPA										
ECONOMIZER INLET		19.305	19.160	19.319	19.305	18.285	17.216	17.099	17.161	19.222	19.167
DRUM		18.857	18.802	18.871	18.857	18.037	17.023	16.913	17.016	18.809	18.788
SH OUTLET		17.168	17.058	17.154	17.175	16.961	16.458	16.361	16.465	17.106	17.078
TURBINE 1ST STAGE		12.838	12.810	12.866	12.845	9.735	6.426	6.419	6.384	12.831	12.742
RH INLET		3.820	3.799	3.806	3.799	3.034	2.041	2.048	2.034	3.820	3.785
RH OUTLET		3.585	3.564	3.564	3.564	2.889	1.972	1.972	1.972	3.599	3.571
SH SPRAY WATER		18.657	18.512	18.692	18.506	17.940	17.547	17.444	17.540	18.512	18.499
HP HTR FW INLET		19.519	19,471	19.588	19.546	18.623	17.478	17.395	17.430	19.478	19.505
HP HTR STM INLET		3.792	3.788	3.785	3.758	3.061	2.041	2.048	2.034	3.799	3.771
TEMPERATURES	°C										
WATER AND STEAM											
ECONOMIZER INLET		247	248	246	246	238	218	218	217	248	250
ECONOMIZER OUTLET	L	325	333	333	339	329	301	308	321	329	330
ECONOMIZER OUTLET	LC	328	336	337	342	331	303	309	322	332	332
ECONOMIZER OUTLET	RC	325	332	333	337	328	301	305	319	331	327
ECONOMIZER OUTLET	R	326	334	335	339	331	299	307	318	331	334
SH DESH INLET LINK	R	396	402	400	403	408	394	399	408	401	400
SH DESH INLET LINK	L	396	397	402	408	407	397	404	413	399	399
SH DESH OUTLET LINK	L	395	390	401	403	403	391	391	393	393	399
SH DESH OUTLET LINK	R	394	396	398	400	400	388	388	391	399	398
SH DIV PANEL OUTLET LINK	L	426	439	436	437	440	438	436	443	438	436
SH DIV PANEL OUTLET LINK	R	435	438	441	441	435	434	433	434	434	435
SH PEND SPCD FRONT INLET LINK	L	482	493	493	493	502	514	509	513	492	490
SH PEND SPCD FRONT INLET LINK	C	489	493	494	493	501	518	506	508	492	489
SH PEND SPCD FRONT INLET LINK	R	494	486	490	491	499	502	498	493	488	491
SH OUTLET	L	526	540	533	536	547	549	548	552	541	532
SH OUTLET	R	536	541	535	535	546	541	537	537	540	536
RH DESH INLET	L	322	324	324	326	317	288	287	288	327	323
RH DESH INLET	R	323	324	325	326	318	293	292	292	327	324
RH RADIANT WALL INLET	L	321	321	324	324	309	287	286	287	317	323
RH RADIANT WALL INLET	R	322	321	324	326	312	293	292	292	313	323
RH RADIANT WALL OUTLET LINK	L	360	365	359	359	347	340	339	341	358	357
RH RADIANT WALL OUTLET LINK	LC	368	374	366	366	360	350	347	358	366	367
RH RADIANT WALL OUTLET LINK	RC	353	355	349	351	349	336	337	336	349	357
RH RADIANT WALL OUTLET LINK	R	355	363	357	357	345	339	345	339	353	364
RH OUTLET	L	542	550	547	546	547	534	544	546	545	536
RH OUTLET	R	NA	NA	NA	NA	550	525	532	528	NA	NA
RH OUTLET	COMB.	539	548	538	538	550	533	538	539	545	538
HP HEATER STM INLET		321	324	324	326	317	291	290	291	326	324
HP HEATER DRAIN		216	216	216	216	206	188	189	188	216	216
HP HEATER FW IN		209	209	209	209	202	186	186	186	209	209
HP HEATER FW OUT		248	248	247	248	238	218	219	218	251	251
SH DESH SPRAY WATER	L	125	126	127	128	144	144	146	145	128	136
SH DESH SPRAY WATER	R	127	125	128	131	145	144	146	145	130	135
RH DESH SPRAY WATER		127	121	113	112	147	103	104	101	162	112
AIR AND GAS											
AH AIR INLET	L	37	39	36	36	42	42	39	39	38	34
AH AIR INLET	R	42	42	39	39	41	41	39	41	43	38
AH AIR OUTLET	L	273	274	273	275	267	243	248	248	275	271
AH AIR OUTLET	R	268	268	265	268	271	245	248	246	271	266
AH GAS INLET	L	328	336	341	347	326	282	291	298	334	336
AH GAS INLET	R	332	337	341	347	332	289	294	302	337	340
AH GAS OUTLET	L	122	126	122	122	122	109	111	109	127	123
AH GAS OUTLET	R	118	119	122	123	125	107	104	106	120	119

BASELINE OPERATION STUDY

TEST DATA

TEST NO.		10	11	12	13	14	15	16	17	18	19
DATE	1975	5/1	7/17	7/18	5/9	5/9	5/9	10/9	7/22	7/21	7/21
UNIT LOAD	MW	428	256	259	433	433	433	361	258	260	258
FLOWS	KG/SEC										
FEEDWATER		344	198	198	377	375	373	297	204	204	198
1ST STAGE STEAM		370	186	190	373	374	374	280	189	190	188
PRESSURES	MPA										
ECONOMIZER INLET		19.181	17.106	14.582	19.271	19.285	19.298	18.368	17.299	17.050	17.030
DRUM		18.768	16.940	14.417	18.850	18.871	18.878	18.078	17.078	16.844	16.844
SH OUTLET		17.044	16.382	13.720	17.175	17.237	17.175	16.961	16.527	16.265	16.272
TURBINE 1ST STAGE		12.776	6.371	6.550	12.852	12.866	12.866	9.694	6.488	6.536	6.467
RH INLET		3.778	2.034	2.041	3.840	3.847	3.826	3.047	2.027	2.027	2.027
RH OUTLET		3.551	1.965	1.979	3.627	3.627	3.606	2.923	1.965	1.965	1.958
SH SPRAY WATER		18.478	17.437	14.934	18.692	18.657	18.712	17.830	17.526	17.375	17.375
HP HTR FW INLET		19.498	17.382	14.844	19.560	19.588	19.616	18,692	17.575	17.313	17.285
HP HTR STM INLET		3.771	2.034	2.055	3.847	3.820	3.854	3.075	2.034	2.034	2.034
TEMPERATURES	°C										
WATER AND STEAM											
ECONOMIZER INLET		252	217	218	248	247	247	238	217	217	217
ECONOMIZER OUTLET	L	342	304	317	331	340	348	327	302	304	317
ECONOMIZER OUTLET	LC	343	304	319	339	345	356	329	304	306	319
ECONOMIZER OUTLET	RC	342	303	317	339	342	351	325	303	304	317
ECONOMIZER OUTLET	R	347	303	316	329	341	357	328	299	304	316
SH DESH INLET LINK	R	403	398	409	398	399	408	408	396	399	409
SH DESH INLET LINK	L	402	401	412	399	401	409	407	399	399	412
SH DESH OUTLET LINK	L	399	391	386	396	399	408	407	397	396	396
SH DESH OUTLET LINK	R	401	388	382	400	401	403	404	398	393	393
SH DIV PANEL OUTLET LINK	L	449	438	435	433	434	439	446	440	440	439
SH DIV PANEL OUTLET LINK	R	441	436	433	433	436	441	440	438	435	434
SH PEND SPCD FRONT INLET LINK	L	501	508	504	488	493	494	508	506	509	505
SH PEND SPCD FRONT INLET LINK	C	498	509	505	489	494	493	501	508	507	503
SH PEND SPCD FRONT INLET LINK	R	490	503	498	486	487	491	496	NA	NA	NA
SH OUTLET	L	546	545	544	532	537	541	551	545	545	547
SH OUTLET	R	544	541	541	532	536	538	544	537	536	537
RH DESH INLET	L	326	287	303	326	327	330	317	284	286	286
RH DESH INLET	R	327	292	312	326	328	331	322	289	291	292
RH RADIANT WALL INLET	L	325	286	302	311	311	309	299	283	284	285
RH RADIANT WALL INLET	R	326	292	312	313	313	314	304	289	291	292
RH RADIANT WALL OUTLET LINK	L	363	340	346	344	344	351	340	337	336	336
RH RADIANT WALL OUTLET LINK	LC	376	352	361	351	349	354	347	344	343	343
RH RADIANT WALL OUTLET LINK	RC	362	341	353	342	341	343	342	332	333	333
RH RADIANT WALL OUTLET LINK	R	370	346	353	350	347	348	339	333	339	338
RH OUTLET	L	542	537	534	544	542	545	546	542	542	540
RH OUTLET	R	NA	535	534	NA	NA	NA	543	525	528	531
RH OUTLET	COMB.	548	538	536	539	539	542	546	538	538	537
HP HEATER STM INLET		325	291	308	325	327	329	318	288	289	290
HP HEATER DRAIN		216	188	188	217	217	217	206	188	188	188
HP HEATER FW IN		209	186	186	210	210	210	202	185	185	186
HP HEATER FW OUT		253	219	219	249	248	248	238	218	218	218
SH DESH SPRAY WATER	L	138	145	144	128	125	129	144	141	143	144
SH DESH SPRAY WATER	R	138	145	144	125	123	127	139	137	143	144
RH DESH SPRAY WATER		118	108	108	165	163	170	157	107	102	104
AIR AND GAS											
AH AIR INLET	L	39	42	46	37	38	38	47	39	39	39
AH AIR INLET	R	43	41	44	43	44	41	42	40	38	42
AH AIR OUTLET	L	277	246	248	263	274	271	263	247	247	250
AH AIR OUTLET	R	273	248	246	258	271	263	270	247	249	248
AH GAS INLET	L	349	288	298	331	339	346	327	288	290	298
AH GAS INLET	R	351	292	302	337	341	351	331	292	296	302
AH GAS OUTLET	L	127	111	117	128	129	129	122	117	115	116
AH GAS OUTLET	R	126	108	106	122	122	125	121	110	111	109

BIASED FIRING OPERATION STUDY

TEST DATA

TEST NO.		1	2	3	4	5	6	7	8
DATE	1975	9/17	9/18	9/20	12/13	10/11	10/12	10/12	10/5
UNIT LOAD	MW	430	426	434	356	351	360	257	270
FLOWS	KG/SEC								
FEEDWATER		375	370	369	297	295	299	218	207
1ST STAGE STEAM		359	359	359	288	280	288	180	200
PRESSURES	MPA								
ECONOMIZER INLET		19.154	19.133	19.098	18.381	18.381	18.278	17.588	17.588
DRUM		18.712	18.636	18.616	18.071	18.085	17.975	17.451	17.430
SH OUTLET		17.044	16.940	16.913	16.961	16.940	16.961	16.892	16.844
TURBINE 1ST STAGE		12.438	12.397	12.417	9.935	9.611	9.956	6.743	6.922
RH INLET		3.771	3.764	3.778	3.047	2.985	3.068	2.137	2.227
RH OUTLET		3.613	3.592	3.613	2.882	2.903	2.937	2.068	2.151
SH SPRAY WATER		18.512	18.450	NA	17.975	17.975	17.893	17.561	NA
HP HTR FW INLET		19.554	19.512	19.305	18.630	18.643	18.636	17.926	17.933
HP HTR STM INLET		3.806	3.792	3.820	3.040	3.034	3.116	2.144	2.248
TEMPERATURES	°C								
WATER AND STEAM									
ECONOMIZER INLET		249	248	249	238	237	238	219	221
ECONOMIZER OUTLET	L	329	330	332	314	319	319	302	312
ECONOMIZER OUTLET	LC	333	333	336	315	322	321	304	313
ECONOMIZER OUTLET	RC	331	331	333	313	319	318	301	312
ECONOMIZER OUTLET	R	333	333	333	318	323	321	306	313
SH DESH INLET LINK	R	402	401	402	393	403	398	398	405
SH DESH INLET LINK	L	398	399	403	397	399	396	395	404
SH DESH OUTLET LINK	L	402	400	401	393	403	398	398	390
SH DESH OUTLET LINK	R	397	399	403	397	399	396	395	387
SH DIV PANEL OUTLET LINK	L	432	432	442	438	438	438	438	435
SH DIV PANEL OUTLET LINK	R	422	423	427	444	433	433	434	424
SH PEND SPCD FRONT INLET LINK	L	479	488	502	508	495	508	506	509
SH PEND SPCD FRONT INLET LINK	C	476	484	493	515	496	501	507	505
SH PEND SPCD FRONT INLET LINK	R	468	473	477	507	489	502	505	492
SH OUTLET	L	521	529	543	546	536	544	540	547
SH OUTLET	R	517	521	525	543	536	540	543	539
RH DESH INLET	L	315	319	327	315	306	314	286	288
RH DESH INLET	R	314	318	326	317	309	316	291	NA
RH RADIANT WALL INLET	L	313	317	314	314	301	309	284	287
RH RADIANT WALL INLET	R	314	318	316	317	306	312	292	294
RH RADIANT WALL OUTLET LINK	L	351	356	359	353	337	349	329	336
RH RADIANT WALL OUTLET LINK	LC	363	366	374	368	350	364	348	350
RH RADIANT WALL OUTLET LINK	RC	348	348	344	356	342	352	337	335
RH RADIANT WALL OUTLET LINK	R	349	344	341	354	336	346	333	329
RH OUTLET	L	530	543	551	552	531	544	526	546
RH OUTLET	R	542	538	531	527	543	547	542	543
RH OUTLET	COMB.	538	542	543	541	539	546	536	548
HP HEATER STM INLET		314	318	327	316	308	316	289	292
HP HEATER DRAIN		217	217	217	205	206	207	189	192
HP HEATER FW IN		211	212	211	202	201	202	187	188
HP HEATER FW OUT		250	249	251	238	237	239	220	222
SH DESH SPRAY WATER	L	133	139	131	126	123	124	117	147
SH DESH SPRAY WATER	R	134	140	132	126	124	125	117	147
RH DESH SPRAY WATER		134	141	166	142	157	156	116	117
AIR AND GAS									
AH AIR INLET	L	37	37	37	43	42	46	49	48
AH AIR INLET	R	37	39	41	43	37	43	47	46
AH AIR OUTLET	L	279	277	280	261	265	261	244	248
AH AIR OUTLET	R	278	275	277	268	271	265	249	253
AH GAS INLET	L	348	347	349	314	311	319	291	299
AH GAS INLET	R	351	349	349	322	326	322	293	301
AH GAS OUTLET	L	132	132	133	120	125	121	117	121
AH GAS OUTLET	R	124	122	116	120	127	115	111	119

BIASED FIRING OPERATION STUDY

TEST DATA

TEST NO.		9	10	11	12	13	14	15	16
DATE	1975	9/17	9/18	9/18	10/11	12/13	12/13	7/23	7/24
UNIT LOAD	MW	429	428	429	351	356	356	256	259
FLOWS	KG/SEC								
FEEDWATER		375	370	369	295	299	299	201	204
1ST STAGE STEAM		357	360	359	277	288	285	186	190
PRESSURES	MPA								
ECONOMIZER INLET		19.174	19.154	19.098	18.381	18.368	18.416	17.264	17.299
DRUM		18.657	18.671	18.657	18.050	18.064	18.037	17.058	17.113
SH OUTLET		16.989	17.023	16.961	16.927	16.858	16.906	16.534	16.575
TURBINE 1ST STAGE		12.397	12.486	12.438	9.577	9.942	9.908	6.467	6.640
RH INLET		3.771	3.778	3.778	2.978	3.040	3.040	2.006	2.048
RH OUTLET		3.592	3.613	3.613	2.896	2.896	2.875	1.944	1.986
SH SPRAY WATER		18.457	18.416	18.485	17.699	18.023	17.975	17.588	17.637
HP HTR FW INLET		19.581	19.609	19.526	18.726	18.761	18.685	17.520	17.602
HP HTR STM INLET		3.799	3.806	3.806	3.013	3.040	3.040	2.013	2.041
TEMPERATURES	°C								
WATER AND STEAM									
ECONOMIZER INLET		248	248	249	236	237	238	217	217
ECONOMIZER OUTLET	L	331	334	336	322	318	319	304	304
ECONOMIZER OUTLET	LC	336	337	339	326	318	319	307	306
ECONOMIZER OUTLET	RC	334	334	336	322	316	320	305	303
ECONOMIZER OUTLET	R	335	337	339	325	323	324	303	304
SH DESH INLET LINK	R	403	405	407	404	397	398	400	399
SH DESH INLET LINK	L	399	402	405	402	399	399	401	402
SH DESH OUTLET LINK	L	403	404	406	404	396	397	398	393
SH DESH OUTLET LINK	R	399	402	404	402	399	398	396	390
SH DIV PANEL OUTLET LINK	L	431	437	438	438	436	442	441	437
SH DIV PANEL OUTLET LINK	R	423	429	431	435	445	442	438	437
SH PEND SPCD FRONT INLET LINK	L	477	494	494	494	503	512	504	501
SH PEND SPCD FRONT INLET LINK	C	474	494	488	496	505	506	510	504
SH PEND SPCD FRONT INLET LINK	R	466	488	479	491	511	505	499	502
SH OUTLET	L	518	537	537	537	542	547	545	543
SH OUTLET	R	513	535	529	536	544	542	542	541
RH DESH INLET	L	311	327	327	307	312	313	287	286
RH DESH INLET	R	311	NA	NA	309	314	316	291	291
RH RADIANT WALL INLET	L	309	312	310	306	311	310	286	284
RH RADIANT WALL INLET	R	311	314	314	309	314	314	291	291
RH RADIANT WALL OUTLET LINK	L	343	346	348	342	350	358	329	334
RH RADIANT WALL OUTLET LINK	LC	357	360	358	354	359	364	346	351
RH RADIANT WALL OUTLET LINK	RC	341	346	343	346	352	350	338	339
RH RADIANT WALL OUTLET LINK	R	339	342	340	340	355	352	337	345
RH OUTLET	L	518	533	542	534	547	549	532	536
RH OUTLET	R	532	541	539	541	534	532	533	NA
RH OUTLET	COMB.	530	539	542	539	540	540	538	537
HP HEATER STM INLET		311	327	326	308	313	314	289	289
HP HEATER DRAIN		217	217	217	206	205	205	187	188
HP HEATER FW IN		211	211	211	201	201	201	185	185
HP HEATER FW OUT		249	251	250	237	238	238	218	218
SH DESH SPRAY WATER	L	134	133	152	127	131	140	143	143
SH DESH SPRAY WATER	R	134	134	152	127	131	138	143	143
RH DESH SPRAY WATER		152	165	166	145	147	156	104	104
AIR AND GAS									
AH AIR INLET	L	36	37	37	43	43	43	40	40
AH AIR INLET	R	37	39	38	41	42	42	39	40
AH AIR OUTLET	L	279	277	280	263	262	262	247	248
AH AIR OUTLET	R	278	276	278	268	271	269	249	248
AH GAS INLET	L	350	344	351	322	320	315	286	290
AH GAS INLET	R	353	351	355	328	326	329	292	294
AH GAS OUTLET	L	132	132	132	123	124	122	119	122
AH GAS OUTLET	R	125	124	124	119	121	121	113	112

OVERFIRE AIR OPERATION STUDY

TEST DATA

TEST NO.		1	2	3	4	5	6	7	8
Date	1975	9/17	9/26	9/26	9/26	9/26	10/1	10/1	10/1
Unit Load	MW	428	430	430	430	431	430	429	428
FLOWS	kg/sec								
Feedwater		369	372	372	370	370	372	372	370
1st Stage Steam		358	364	364	362	364	362	362	360
PRESSURES	MPa								
Economizer Inlet		19.126	19.167	19.195	19.188	19.236	19.209	19.147	19.133
Drum		18.657	18.685	18.726	18.692	18.726	18.678	18.685	18.643
SH Outlet		16.975	17.009	17.023	17.009	17.037	16.961	17.009	16.989
Turbine 1st Stage		12.452	12.569	12.569	12.528	12.590	12.535	12.535	12.500
RH Inlet		3.765	3.771	3.785	3.792	3.806	3.771	3.771	3.765
RH Outlet		3.606	3.613	3.613	3.627	3.627	3.592	3.613	3.599
SH Spray Water		18.471	18.388	18.388	18.388	18.388	18.388	18.388	18.388
HP Htr FW Inlet		19.478	19.809	19.733	19.588	19.657	19.540	19.650	19.560
HP Htr Stm Inlet		3.799	3.799	3.806	3.827	3.827	3.785	3.799	3.799
TEMPERATURES	°C								
Water and Steam									
Economizer Inlet		249	248	248	249	249	248	248	248
Economizer Outlet	L	336	334	334	333	335	330	330	331
Economizer Outlet	LC	339	337	337	337	339	334	334	335
Economizer Outlet	RC	336	334	334	334	337	332	331	333
Economizer Outlet	R	339	338	337	336	336	334	333	334
SH DESH Inlet Link	R	406	407	406	404	404	404	403	405
SH DESH Inlet Link	L	404	402	403	402	403	400	401	402
SH DESH Outlet Link	L	406	406	405	403	404	404	403	404
SH DESH Outlet Link	R	403	401	402	402	403	400	400	402
SH Div Panel Outlet Link	L	437	438	438	440	439	440	436	438
SH Div Panel Outlet Link	R	429	429	429	430	432	430	429	431
SH Pend Spcd Front Inlet Link	L	492	490	491	496	493	496	491	491
SH Pend Spcd Front Inlet Link	C	489	482	485	490	488	489	483	486
SH Pend Spcd Front Inlet Link	R	480	479	476	481	477	480	475	476
SH Outlet	L	534	531	534	538	537	537	533	534
SH Outlet	R	529	527	526	529	527	530	523	526
RH DESH Inlet	L	324	322	322	326	324	326	321	322
RH DESH Inlet	R	323	NA	NA	326	323	NA	NA	323
RH Radiant Wall Inlet	L	316	314	314	311	311	324	319	321
RH Radiant Wall Inlet	R	316	315	314	312	312	324	319	322
RH Radiant Wall Outlet Link	L	351	350	348	346	347	359	354	358
RH Radiant Wall Outlet Link	LC	363	357	359	361	360	368	362	364
RH Radiant Wall Outlet Link	RC	346	347	348	347	345	359	354	356
RH Radiant Wall Outlet Link	R	344	352	349	347	342	357	352	351
RH Outlet	L	539	533	536	534	538	543	543	546
RH Outlet	R	539	544	539	539	534	550	539	541
RH Outlet	Comb.	540	538	538	539	539	548	542	545
HP Heater Stm Inlet		323	321	322	325	324	325	321	322
HP Heater Drain		217	216	216	217	217	216	216	216
HP Heater FW In		211	211	211	211	211	211	211	211
HP Heater FW Out		250	249	249	250	250	249	249	249
SH DESH Spray Water	L	136	130	131	132	132	132	132	132
SH DESH Spray Water	R	137	131	132	132	132	133	133	133
RH DESH Spray Water		166	166	166	166	166	132	132	132
Air and Gas									
AH Air Inlet	L	37	33	32	32	32	43	43	43
AH Air Inlet	R	38	44	43	43	43	30	31	30
AH Air Outlet	L	281	282	283	281	282	272	272	274
AH Air Outlet	R	279	276	276	273	274	285	284	284
AH Gas Inlet	L	351	337	338	338	340	339	339	341
AH Gas Inlet	R	356	348	348	346	346	349	348	347
AH Gas Outlet	L	133	138	138	137	138	126	126	125
AH Gas Outlet	R	125	122	122	120	121	129	129	131

OVERFIRE AIR OPERATION STUDY

TEST DATA

TEST NO.		9	10	11	12	13	14	15	16
Date	1975	9/27	10/1	10/1	10/5	10/4	10/5	10/4	10/3
Unit Load	MW	428	429	430	427	434	422	429	427
FLOWS	kg/sec								
Feedwater		369	369	370	370	364	370	370	372
1st Stage Steam		365	362	362	360	360	359	362	360
PRESSURES	MPa								
Economizer Inlet		19.195	19.147	19.147	19.078	19.119	19.119	19.092	19.119
Drum		18.726	18.685	18.678	18.685	18.650	18.678	18.657	18.630
SH Outlet		16.975	16.989	17.003	16.989	16.996	16.947	16.996	16.989
Turbine 1st Stage		12.604	12.535	12.521	12.500	12.500	12.466	12.535	12.486
RH Inlet		3.771	3.751	3.758	3.751	3.778	3.751	3.771	3.771
RH Outlet		3.599	3.627	3.585	3.599	3.606	3.585	3.606	3.599
SH Spray Water		18.388	18.388	18.388	18.388	18.388	18.388	18.388	18.388
HP Htr FW Inlet		19.664	19.595	19.560	19.588	19.595	19.595	19.526	19.547
HP Htr Stm Inlet		3.799	3.758	3.765	3.806	3.827	3.792	3.799	3.799
TEMPERATURES	°C								
Water and Steam									
Economizer Inlet		248	248	248	248	249	248	248	248
Economizer Outlet	L	341	341	341	332	333	328	331	329
Economizer Outlet	LC	342	344	344	334	337	332	333	335
Economizer Outlet	RC	338	342	342	330	335	329	331	333
Economizer Outlet	R	343	342	342	332	338	329	333	332
SH DESH Inlet Link	R	406	409	409	400	408	398	401	402
SH DESH Inlet Link	L	404	407	408	401	402	398	399	398
SH DESH Outlet Link	L	406	409	409	399	407	398	401	402
SH DESH Outlet Link	R	403	407	408	401	402	398	398	398
SH Div Panel Outlet Link	L	436	438	441	432	446	432	438	435
SH Div Panel Outlet Link	R	428	436	437	428	436	425	429	430
SH Pend Spcd Front Inlet Link	L	489	489	489	487	503	485	494	484
SH Pend Spcd Front Inlet Link	C	484	492	493	482	500	500	491	492
SH Pend Spcd Front Inlet Link	R	479	483	482	479	489	489	480	481
SH Outlet	L	531	537	537	529	546	526	534	528
SH Outlet	R	525	533	533	523	539	514	527	530
RH DESH Inlet	L	321	326	326	319	333	315	323	322
RH DESH Inlet	R	NA	NA	NA	NA	NA	NA	NA	NA
RH Radiant Wall Inlet	L	319	324	324	317	320	313	322	314
RH Radiant Wall Inlet	R	319	325	325	318	321	314	322	315
RH Radiant Wall Outlet Link	L	351	354	354	355	352	350	354	348
RH Radiant Wall Outlet Link	LC	359	364	365	362	365	362	367	355
RH Radiant Wall Outlet Link	RC	347	352	354	349	357	343	355	348
RH Radiant Wall Outlet Link	R	346	349	348	345	352	337	353	341
RH Outlet	L	539	541	541	548	541	534	541	528
RH Outlet	R	540	539	539	532	554	516	545	538
RH Outlet	Comb.	539	543	543	540	550	529	544	538
HP Heater Stm Inlet		320	325	325	318	332	314	323	322
HP Heater Drain		216	216	216	216	217	216	216	216
HP Heater FW In		210	210	210	211	211	209	211	211
HP Heater FW Out		249	249	249	249	250	248	249	249
SH DESH Spray Water	L	131	131	132	138	137	143	141	151
SH DESH Spray Water	R	132	132	132	138	138	143	141	147
RH DESH Spray Water		124	130	131	136	166	147	164	166
Air and Gas									
AH Air Inlet	L	34	41	41	39	39	41	40	35
AH Air Inlet	R	39	31	31	34	33	35	34	34
AH Air Outlet	L	280	277	278	277	277	274	275	274
AH Air Outlet	R	276	284	285	281	284	279	281	281
AH Gas Inlet	L	342	351	350	343	343	341	342	343
AH Gas Inlet	R	352	354	355	348	352	346	348	346
AH Gas Outlet	L	135	128	129	131	130	129	131	129
AH Gas Outlet	R	124	131	132	131	130	122	131	128

OVERFIRE AIR OPERATION STUDY

TEST DATA

TEST NO.		17	18	19	20	21	22	23	24
DATE	1975	10/3	10/3	10/6	10/8	10/9	10/9	10/12	10/5
UNIT LOAD	MW	424	429	417	426	356	358	253	265
FLOWS	KG/SEC								
FEEDWATER		377	367	374	377	299	299	218	216
1ST STAGE STEAM		362	362	359	360	282	282	193	199
PRESSURES	MPA								
ECONOMIZER INLET		19.092	19.099	19.105	19.188	18.381	18.450	17.623	17.561
DRUM		18.650	18.642	18.733	18.761	18.099	18.092	17.416	17.389
SH OUTLET		16.968	16.996	16.996	16.996	16.996	16.927	16.927	16.727
TURBINE 1ST STAGE		12.521	12.500	12.486	12.500	9.770	9.756	6.640	6.847
RH INLET		3.778	3.778	3.751	3.765	3.034	3.054	2.213	2.199
RH OUTLET		3.613	3.599	3.599	3.599	2.896	2.965	2.096	2.082
SH SPRAY WATER		18.388	18.388	18.388	18.388	18.009	18.044	17.568	17.533
HP HTR FW INLET		19.526	19.547	19.547	19.560	18.712	18.747	17.933	17.899
HP HTR STM INLET		3.799	3.820	3.799	3.799	3.075	3.075	2.213	2.213
TEMPERATURES	°C								
WATER AND STEAM									
ECONOMIZER INLET		248	249	247	248	237	237	218	220
ECONOMIZER OUTLET	L	328	332	327	326	316	322	299	305
ECONOMIZER OUTLET	LC	332	336	328	329	318	326	300	307
ECONOMIZER OUTLET	RC	329	333	326	326	314	321	297	305
ECONOMIZER OUTLET	R	331	334	328	329	317	323	301	306
SH DESH INLET LINK	R	399	403	396	397	396	402	392	396
SH DESH INLET LINK	L	397	401	396	396	396	403	391	397
SH DESH OUTLET LINK	L	399	403	396	397	395	402	391	396
SH DESH OUTLET LINK	R	397	401	395	394	395	403	391	392
SH DIV PANEL OUTLET LINK	L	434	438	429	432	436	444	429	441
SH DIV PANEL OUTLET LINK	R	424	432	423	423	428	436	423	426
SH PEND SPCD FRONT INLET LINK	L	482	493	486	487	496	499	497	513
SH PEND SPCD FRONT INLET LINK	C	481	491	484	484	498	499	493	515
SH PEND SPCD FRONT INLET LINK	R	468	486	473	471	486	486	484	490
SH OUTLET	L	522	536	526	525	534	542	528	549
SH OUTLET	R	516	534	518	517	528	533	522	536
RH DESH INLET	L	313	327	316	315	303	308	271	286
RH DESH INLET	R	NA	NA	316	314	306	313	277	292
RH RADIANT WALL INLET	L	301	312	314	313	302	301	270	284
RH RADIANT WALL INLET	R	302	314	316	314	305	304	277	292
RH RADIANT WALL OUTLET LINK	L	334	351	352	348	339	342	313	329
RH RADIANT WALL OUTLET LINK	LC	346	358	362	361	359	357	327	342
RH RADIANT WALL OUTLET LINK	RC	332	347	346	344	341	339	313	326
RH RADIANT WALL OUTLET LINK	R	331	343	343	344	336	337	311	324
RH OUTLET	L	514	539	541	527	529	542	511	529
RH OUTLET	R	516	538	536	526	526	531	509	522
RH OUTLET	COMB.	518	541	536	528	529	539	511	530
HP HEATER STM INLET		312	327	316	314	304	310	274	289
HP HEATER DRAIN		216	217	215	216	206	206	189	191
HP HEATER FW IN		210	211	209	210	202	202	186	187
HP HEATER FW OUT		249	250	248	249	238	238	219	221
SH DESH SPRAY WATER	L	137	143	133	135	126	134	119	144
SH DESH SPRAY WATER	R	137	141	133	136	127	134	121	145
RH DESH SPRAY WATER		164	165	144	131	135	157	118	122
AIR AND GAS									
AH AIR INLET	L	40	39	39	41	42	47	49	48
AH AIR INLET	R	34	34	34	36	42	43	49	44
AH AIR OUTLET	L	274	277	273	273	262	261	242	244
AH AIR OUTLET	R	280	281	278	278	267	268	247	251
AH GAS INLET	L	340	346	337	337	317	325	288	296
AH GAS INLET	R	345	348	346	346	322	328	290	298
AH GAS OUTLET	L	129	129	129	129	123	121	117	121
AH GAS OUTLET	R	128	128	128	127	123	121	116	116

BASELINE OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	2A	3	4	5	6	7	8	9
DATE	1975	5/7	5/5	5/7	5/7	10/10	7/16	7/15	7/16	5/5	4/30
UNIT LOAD	MW	429	427	428	428	360	259	260	258	430	428
FLOWS	KG/S										
FEEDWATER (MEASURED)		375	375	377	377	295	201	198	195	375	377
AUXILIARY STEAM - SH (PLANT INSTRUMENTATION)		0.4	0.4	0.4	0.4	0.4	0.4	0.4	1.1	0.4	0.4
SH SPRAY (HEAT BALANCE)		1	5	0	3	4	3	5	8	3	0
MAIN STEAM (CALCULATED)		376	380	377	380	298	204	203	202	378	377
TURBINE LEAKAGE (TURBINE HEAT BALANCE)		7	7	7	7	6	4	4	4	7	7
HP HTR. EXTRACTION (HEAT BALANCE)		32	32	30	31	23	13	13	13	33	35
RH SPRAY (HEAT BALANCE)		0	1	0	0	2	0	0	0	5	0
RH STEAM (CALCULATED)		337	343	339	342	272	186	186	185	342	335
UNIT ABSORPTION	MJ/S										
ECONOMIZER		153	171	177	189	141	82	87	100	162	160
FURNACE		371	353	352	340	294	241	232	214	361	363
DRUM - SH DESH		142	149	153	163	126	71	76	83	150	150
SH DESH - SH OUTLET		198	212	190	190	153	112	109	108	205	191
REHEATER		172	182	170	170	149	99	103	102	184	168
TOTAL		1036	1068	1041	1051	862	605	608	607	1063	1032
UNIT EFFICIENCY	%										
DRY GAS LOSS		3.55	3.71	3.96	4.27	4.12	3.07	3.18	3.70	3.70	3.90
MOISTURE IN FUEL LOSS		5.35	4.89	4.99	5.13	4.99	4.94	4.78	4.92	5.04	5.06
MOISTURE IN AIR LOSS		0.11	0.11	0.12	0.13	0.13	0.09	0.10	0.11	0.11	0.12
RADIATION LOSS		0.19	0.18	0.18	0.18	0.22	0.31	0.31	0.31	0.18	0.19
ASH PIT LOSS		0.34	0.34	0.32	0.36	0.33	0.29	0.30	0.30	0.33	0.32
HEAT IN FLY ASH LOSS		0.02	0.02	0.02	0.03	0.02	0.01	0.01	0.01	0.02	0.02
PYRITE REJECTION LOSS		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CARBON LOSS		0.52	0.37	0.22	0.31	0.12	0.23	0.30	0.12	0.68	0.29
TOTAL LOSSES		10.08	9.63	9.84	10.44	9.95	8.95	8.99	9.49	10.07	9.90
EFFICIENCY		89.92	90.37	90.16	89.56	90.05	91.05	91.05	90.51	89.93	90.10
HEAT INPUT	MJ/S										
HEAT INPUT FROM FUEL		1152	1182	1155	1173	958	665	668	671	1182	1146
EXCESS AIR	%										
AIR HEATER INLET		18.9	27.4	32.9	40.9	28.9	23.7	32.1	50.0	19.5	29.0
AIR HEATER OUTLET		26.7	37.2	42.8	52.1	52.1	40.0	40.9	67.9	33.7	40.1

BASELINE OPERATION STUDY

TEST RESULTS

TEST NO.		10	11	12	13	14	15	16	17	18	19
DATE	1975	5/1	7/17	7/18	5/9	5/9	5/9	10/9	7/22	7/21	7/21
UNIT LOAD	MW	428	256	259	433	433	433	361	258	260	258
FLOWS	KG/S										
FEEDWATER (MEASURED)		374	198	198	377	375	374	297	204	204	198
AUXILIARY STEAM - SH (PLANT INSTRUMENTATION)		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
SH SPRAY (HEAT BALANCE)		2	5	9	0	0	2	1	0	2	6
MAIN STEAM (CALCULATED)		375	203	208	377	375	375	298	204	206	205
TURBINE LEAKAGE (TURBINE HEAT BALANCE)		7	4	4	7	7	7	6	4	4	4
HP HTR. EXTRACTION (HEAT BALANCE)		36	13	13	32	31	31	23	14	14	13
RH SPRAY (HEAT BALANCE)		0	0	0	5	6	7	0	0	0	0
RH STEAM (CALCULATED)		333	186	190	343	342	345	269	186	188	187
UNIT ABSORPTION	MJ/S										
ECONOMIZER		188	84	99	174	193	225	137	86	87	100
FURNACE		328	236	236	351	331	297	301	243	243	221
DRUM - SH DESH		156	74	81	149	150	167	127	74	76	84
SH DESH - SH OUTLET		199	110	106	191	191	184	148	102	104	105
REHEATER		172	102	96	184	183	187	151	101	104	103
TOTAL		1042	606	619	1049	1049	1059	864	606	613	613
UNIT EFFICIENCY	%										
DRY GAS LOSS		4.37	3.05	3.50	3.53	3.63	3.94	3.53	3.35	3.60	3.85
MOISTURE IN FUEL LOSS		5.09	4.93	4.88	4.90	4.87	4.93	4.93	4.95	4.96	4.85
MOISTURE IN AIR LOSS		0.13	0.09	0.11	0.11	0.11	0.12	0.11	0.10	0.11	0.12
RADIATION LOSS		0.18	0.31	0.31	0.18	0.18	0.18	0.22	0.31	0.31	0.31
ASH PIT LOSS		0.33	0.29	0.30	0.34	0.34	0.34	0.32	0.31	0.32	0.33
HEAT IN FLY ASH LOSS		0.02	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.01	0.02
PYRITE REJECTION LOSS		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CARBON LOSS		0.23	0.24	0.13	0.53	0.50	0.15	0.09	0.21	0.26	0.17
TOTAL LOSSES		10.36	8.93	9.25	9.62	9.66	9.70	9.22	9.26	9.57	9.66
EFFICIENCY		89.64	91.07	90.75	90.38	90.34	90.30	90.78	90.74	90.43	90.34
HEAT INPUT	MJ/S										
HEAT INPUT FROM FUEL		1163	666	682	1161	1161	1172	951	668	678	678
EXCESS AIR	%										
AIR HEATER INLET		40.9	27.4	48.8	15.0	20.2	35.5	23.0	25.2	28.9	47.8
AIR HEATER OUTLET		55.4	36.4	61.3	25.9	30.5	44.8	38.2	39.1	47.8	61.4

BASELINE OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	2A	3	4	5	6	7	8	9
DATE	1975	5/7	5/5	5/7	5/7	10/10	7/16	7/15	7/16	5/5	4/30
UNIT LOAD	MW	429	427	428	428	360	259	260	258	430	428
PRODUCTS OF COMBUSTION	MG/J										
AIR HEATER INLET											
DRY AIR		425	438	458	489	487	442	452	533	430	447
WET AIR		432	445	466	497	496	450	460	542	438	454
DRY PRODUCTS		405	413	434	460	420	397	431	484	391	418
WET PRODUCTS		414	419	439	466	426	404	437	489	397	426
AIR HEATER OUTLET											
DRY AIR		335	319	321	321	321	316	321	317	322	319
WET AIR		399	406	427	453	413	391	424	476	385	412
DRY PRODUCTS		440	450	471	502	500	456	465	546	443	461
WET PRODUCTS		468	477	498	530	528	483	491	574	470	488
GAS AND AIR FLOWS	KG/S										
GAS ENTERING AIR HEATER		508	526	538	579	434	286	309	346	500	518
GAS LEAVING AIR HEATER		539	564	575	622	506	321	328	385	555	560
AIR ENTERING AIR HEATER		498	526	538	583	475	299	307	363	517	521
AIR LEAVING AIR HEATER		467	488	501	540	402	264	288	324	462	480
AIR HEATER LEAKAGE		31	38	37	43	72	35	19	39	55	41
AIR HEATER PERFORMANCE											
AIR HEATER LEAKAGE	%	6.0	7.2	6.9	7.4	16.7	12.2	6.2	11.2	11.0	8.0
GAS SIDE EFFICIENCY	%	70.8	70.4	70.6	70.7	67.1	69.5	71.5	71.3	69.0	69.9
GAS DROP	°C	206	208	214	219	193	170	181	185	204	211
AIR RISE	°C	231	231	231	234	228	203	208	207	233	232
TEMPERATURE HEAD	°C	291	296	303	309	288	244	253	260	296	301
FUEL ANALYSIS											
CARBON	%	63.30	65.50	67.30	61.20	65.30	66.80	68.30	66.30	66.30	64.80
HYDROGEN	%	4.90	5.10	5.30	4.80	5.10	5.20	5.30	5.10	5.30	5.00
NITROGEN	%	0.90	1.20	0.80	0.80	1.30	1.10	1.30	1.20	0.90	0.90
OXYGEN	%	12.10	9.30	9.50	9.90	9.40	11.60	9.70	10.60	10.10	12.40
SULFUR	%	0.50	0.70	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
MOISTURE	%	8.40	7.30	7.70	8.10	8.70	8.70	6.70	8.80	7.10	8.20
ASH	%	9.90	10.90	8.90	14.70	10.90	6.10	8.20	7.50	9.80	8.20
HHV	KJ/KG	25144	27889	28517	25726	27679	28424	28866	28168	27912	27075

BASELINE OPERATION STUDY

TEST RESULTS

TEST NO.		10	11	12	13	14	15	16	17	18	19
DATE	1975	5/1	7/17	7/18	5/9	5/9	5/9	10/9	7/22	7/21	7/21
UNIT LOAD	MW	428	256	259	433	433	433	361	258	260	258
PRODUCTS OF COMBUSTION											
AIR HEATER INLET											
DRY AIR		499	432	516	401	415	464	446	443	473	520
WET AIR		508	440	525	407	422	472	454	450	481	529
DRY PRODUCTS		460	411	484	372	389	442	404	405	420	484
WET PRODUCTS		466	417	489	380	396	448	410	412	426	489
AIR HEATER OUTLET											
DRY AIR		321	317	320	318	318	320	323	318	320	322
WET AIR		453	404	476	366	382	434	397	398	413	476
DRY PRODUCTS		512	446	529	414	429	478	459	456	486	533
WET PRODUCTS		540	473	557	440	454	505	486	483	513	561
GAS AND AIR FLOWS											
GAS ENTERING AIR HEATER	KG/S	573	295	352	470	489	556	415	292	306	350
GAS LEAVING AIR HEATER		628	315	380	511	528	592	462	323	348	380
AIR ENTERING AIR HEATER		590	293	358	473	490	553	431	300	326	359
AIR LEAVING AIR HEATER		535	273	330	432	451	518	384	270	285	329
AIR HEATER LEAKAGE		55	19	28	41	39	35	48	30	42	30
AIR HEATER PERFORMANCE											
AIR HEATER LEAKAGE	%	9.6	6.6	7.9	8.7	7.9	6.4	11.4	10.3	13.6	8.6
GAS SIDE EFFICIENCY	%	70.1	70.9	72.2	68.8	69.7	71.9	70.3	67.9	67.3	70.1
GAS DROP	°C	216	176	184	202	208	222	200	170	171	182
AIR RISE	°C	234	206	202	221	231	228	222	207	209	209
TEMPERATURE HEAD	°C	309	249	255	293	299	309	284	250	254	260
FUEL ANALYSIS											
CARBON	%	65.60	66.50	67.30	64.20	64.80	63.80	67.70	66.80	67.50	67.00
HYDROGEN	%	5.20	5.10	5.30	4.90	4.90	4.90	5.20	5.10	5.30	5.20
NITROGEN	%	0.90	1.30	1.20	1.10	1.20	1.00	1.20	1.30	1.30	1.20
OXYGEN	%	10.60	10.60	9.50	10.30	10.10	10.20	9.40	10.80	9.70	9.50
SULFUR	%	0.40	0.50	0.50	0.50	0.50	0.80	0.50	0.50	0.50	0.50
MOISTURE	%	8.00	9.00	7.70	7.50	7.80	7.60	8.40	9.00	8.00	7.00
ASH	%	9.30	7.00	8.50	11.50	10.70	11.70	7.60	6.50	7.70	9.60
HHV	KJ/KG	27633	28238	28633	27051	27331	26865	28447	28214	28633	28214

BIASED FIRING OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Date	1975	9/17	9/18	9/20	12/13	10/11	10/12	10/12	10/5	9/17	9/10	9/18	10/11	12/13	12/13	7/23	7/24
Unit Load	MW	430	426	434	356	351	360	257	270	429	428	429	351	356	356	256	259
FLOWS	kg/s																
Feedwater (Measured)		375	370	369	297	295	299	218	207	375	370	369	295	299	299	201	204
Auxiliary Steam - SH (Plant Instrumentation)		0.4	0.4	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.4	0.4
SH Spray (Heat Balance)		0	1	0	0	0	0	0	8	0	0	0	0	0	0	2	6
Main Steam (Calculated)		375	371	368	297	295	299	218	214	375	370	369	295	299	299	203	210
Turbine Leakage (Turbine Heat Balance)		7	7	7	6	6	6	5	4	7	7	7	6	6	6	4	4
HP Htr. Extraction (Heat Balance)		32	30	32	23	23	23	15	14	32	32	31	23	24	24	13	14
RH Spray (Heat Balance)		1	0	4	0	1	1	0	0	0	5	6	0	0	1	0	0
RH Steam (Calculated)		336	334	334	268	268	271	199	196	336	336	336	266	270	270	185	192
UNIT ABSORPTION	MJ/s																
Economizer		164	163	166	114	126	124	90	93	170	172	175	132	124	125	87	88
Furnace		360	357	350	323	310	318	256	233	355	347	340	305	319	316	237	241
Drum - SH DESH		150	149	152	107	117	111	79	83	152	155	159	119	114	113	76	77
SH DESH - SH Outlet		173	177	180	161	144	157	112	120	165	180	172	141	157	158	103	117
Reheater		177	175	178	138	144	147	109	112	171	178	182	141	142	142	101	106
Total		1023	1020	1025	843	841	857	646	641	1014	1031	1028	839	855	854	604	629
UNIT EFFICIENCY	%																
Dry Gas Loss		4.13	3.71	3.85	3.63	3.97	3.26	2.97	3.34	4.28	4.35	3.98	3.79	4.06	3.89	3.47	3.52
Moisture in Fuel Loss		5.01	4.99	5.00	4.90	4.91	4.89	4.83	4.85	4.96	4.76	5.07	5.06	4.89	4.99	4.86	4.93
Moisture in Air Loss		0.13	0.11	0.12	0.11	0.12	0.10	0.09	0.10	0.13	0.13	0.12	0.12	0.13	0.12	0.11	0.11
Radiation Loss		0.19	0.19	0.19	0.23	0.23	0.22	0.29	0.30	0.19	0.19	0.19	0.23	0.22	0.22	0.31	0.30
Ash Pit Loss		0.35	0.32	0.31	0.36	0.32	0.32	0.34	0.32	0.34	0.33	0.32	0.34	0.32	0.31	0.33	0.32
Heat in Fly Ash Loss		0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.02	0.02	0.02
Pyrite Rejection Loss		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Carbon Loss		0.26	0.25	0.55	0.61	0.20	0.22	0.46	0.22	0.28	0.24	0.18	0.22	0.38	0.41	0.12	0.20
Total Losses		10.09	9.60	10.03	9.86	9.77	9.03	9.01	9.16	10.20	10.03	9.87	9.79	10.03	9.96	9.23	9.42
Efficiency		89.91	90.40	89.97	90.14	90.23	90.97	90.99	90.84	89.80	89.97	90.13	90.21	89.97	90.04	90.77	90.58
HEAT INPUT	MJ/s																
Heat Input from Fuel		1138	1128	1140	935	932	942	710	706	1129	1147	1141	930	950	948	665	694
EXCESS AIR	%																
Air Heater Inlet		19.8	21.5	20.9	16.8	19.9	20.8	22.6	24.4	26.3	27.4	29.3	29.3	28.0	31.7	25.1	24.7
Air Heater Outlet		36.4	26.2	36.4	35.4	37.3	34.2	37.3	38.1	40.0	47.4	31.7	41.9	48.7	49.9	39.5	38.1

BIASED FIRING OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
DATE	1975	9/17	9/18	9/20	12/13	10/11	10/12	10/12	10/5	9/17	9/10	9/18	10/11	12/13	12/13	7/23	7/24
UNIT LOAD	MW	430	426	434	356	351	360	257	270	429	428	429	351	356	356	256	259
PRODUCTS OF COMBUSTION	μG/J																
AIR HEATER INLET																	
DRY AIR		436	406	436	457	446	431	434	441	446	467	425	466	498	479	442	443
WET AIR		444	413	443	464	454	438	442	448	454	475	432	474	506	487	450	450
DRY PRODUCTS		396	404	399	406	404	401	402	410	416	418	430	438	441	433	409	413
WET PRODUCTS		422	430	425	432	429	427	427	436	442	444	457	465	467	460	435	439
AIR HEATER OUTLET																	
DRY AIR		383	391	386	394	390	388	388	397	403	404	418	425	429	421	397	400
WET AIR		390	398	393	401	396	395	395	403	409	411	425	432	436	428	403	407
DRY PRODUCTS		449	419	449	468	460	444	448	454	460	482	438	480	510	491	455	456
WET PRODUCTS		477	445	476	495	487	470	475	480	487	508	465	507	538	519	482	482
GAS AND AIR FLOWS	KG/S																
GAS ENTERING AIR HEATER		480	485	485	404	400	402	304	307	499	508	522	433	444	436	290	304
GAS LEAVING AIR HEATER		542	502	542	463	454	443	337	339	549	582	531	472	511	492	320	335
AIR ENTERING AIR HEATER		505	466	505	434	423	413	314	316	512	545	494	441	481	462	299	312
AIR LEAVING AIR HEATER		444	449	448	375	369	372	280	285	462	471	484	402	414	406	268	282
AIR HEATER LEAKAGE		61	17	57	60	54	41	34	32	50	74	9	39	67	56	31	30
AIR HEATER PERFORMANCE																	
AIR HEATER LEAKAGE	%	12.7	3.6	11.9	14.7	13.4	10.2	11.1	10.2	10.1	14.5	1.7	9.0	15.0	12.8	10.7	9.9
GAS SIDE EFFICIENCY	%	67.3	70.5	69.5	68.2	65.4	71.0	70.3	68.4	67.9	67.2	70.9	69.8	67.8	68.5	66.5	66.6
GAS DROP	°C	211	218	215	188	182	196	172	173	214	208	224	198	190	191	166	168
AIR RISE	°C	242	238	240	222	228	218	199	204	243	239	242	223	224	223	208	208
TEMPERATURE HEAD	°C	313	309	310	275	279	276	244	253	316	310	316	283	281	279	249	252
FUEL ANALYSIS																	
CARBON	%	66.80	67.50	65.90	70.30	68.00	67.80	66.50	67.00	66.80	65.30	67.60	67.20	71.80	66.10	66.30	67.20
HYDROGEN	%	5.20	5.30	5.10	5.40	5.20	5.30	5.10	5.20	5.10	4.80	5.30	5.20	5.50	5.20	5.20	5.30
NITROGEN	%	1.20	1.30	1.20	1.00	1.40	1.20	1.30	1.30	1.30	1.20	1.40	1.30	1.30	1.20	1.40	1.20
OXYGEN	%	9.70	9.70	10.00	5.70	10.80	9.60	10.60	9.70	10.60	10.70	9.80	10.00	5.80	9.50	9.40	9.60
SULFUR	%	0.50	0.40	0.40	0.50	0.50	0.50	0.50	0.50	0.50	0.40	0.40	0.40	0.50	0.40	0.50	0.50
MOISTURE	%	8.00	7.40	8.10	6.50	6.90	7.60	8.30	7.80	8.00	7.40	8.00	8.10	7.10	8.10	7.40	7.40
ASH	%	8.60	8.40	9.30	10.60	7.20	8.00	7.70	8.50	7.70	10.20	7.50	7.80	8.00	9.50	9.80	8.80
HHV	KJ/KG	28307	28470	27786	28656	28145	28680	28214	28470	28168	27447	28424	27656	29517	28075	28447	28517

OVERFIRE AIR OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12
Date	1975	9/17	9/26	9/26	9/26	9/26	10/1	10/1	10/1	9/27	10/1	10/1	10/5
Unit Load	MW	428	430	430	430	431	430	429	428	428	429	430	427
FLOWS	kg/s												
Feedwater (Measured)		369	372	372	370	370	372	372	370	369	369	370	370
Auxiliary Steam - SH (Plant Instrumentation)		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
SH Spray (Heat Balance)		0	1	0	0	0	0	0	0	0	0	0	0
Main Steam (Calculated)		369	372	372	370	370	372	372	370	369	368	370	370
Turbine Leakage (Turbine Heat Balance)		7	7	7	7	7	7	7	7	7	7	7	7
HP Htr. Extraction (Heat Balance)		31	32	32	32	32	31	32	31	31	32	32	31
RH Spray (Heat Balance)		3	3	3	5	5	0	0	1	0	0	0	0
RH Steam (Calculated)		333	336	336	336	335	333	334	332	331	330	331	332
UNIT ABSORPTION	MJ/s												
Economizer		174	173	173	171	174	165	166	167	185	188	189	164
Furnace		341	348	347	346	343	356	356	352	330	328	329	354
Drum - SH DESH		157	158	158	154	156	153	153	156	158	163	165	149
SH DESH - SH Outlet		173	174	174	179	175	181	177	174	169	169	169	177
Reheater		175	178	177	179	178	174	174	174	172	166	167	174
Total		1020	1030	1029	1029	1026	1029	1025	1023	1014	1015	1019	1018
UNIT EFFICIENCY	%												
Dry Gas Loss		4.52	3.96	4.07	4.06	3.97	3.91	3.94	3.63	4.58	4.86	4.64	4.03
Moisture in Fuel Loss		5.07	5.10	5.11	4.96	5.03	5.09	5.11	5.03	5.08	4.96	5.04	4.95
Moisture in Air Loss		0.14	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.14	0.15	0.14	0.12
Radiation Loss		0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Ash Pit Loss		0.34	0.33	0.33	0.34	0.33	0.33	0.32	0.32	0.32	0.35	0.32	0.32
Heat in Fly Ash Loss		0.03	0.02	0.02	0.03	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.02
Pyrite Rejection Loss		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Carbon Loss		0.20	0.14	0.24	0.30	0.28	0.24	0.59	0.24	0.22	0.27	0.16	0.25
Total Losses		10.49	9.87	10.08	10.01	9.95	9.91	10.30	9.54	10.56	10.82	10.52	9.89
Efficiency		89.51	90.13	89.92	89.99	90.05	90.09	89.70	90.46	89.44	89.18	89.48	90.11
HEAT INPUT	MJ/s												
Heat Input from Fuel		1140	1143	1145	1143	1139	1142	1143	1130	1133	1138	1140	1130
EXCESS AIR	%												
Air Heater Inlet		27.0	28.2	26.2	25.5	25.2	18.5	19.2	19.2	32.1	33.8	33.8	23.1
Air Heater Outlet		46.8	31.8	32.9	35.6	32.6	29.3	30.1	27.8	48.3	57.8	49.5	29.2

OVERFIRE AIR OPERATION STUDY

TEST RESULTS

TEST NO.		13	14	15	16	17	18	19	20	21	22	23	24
DATE	1975	10/4	10/5	10/4	10/3	10/3	10/3	10/6	10/8	10/9	10/9	10/12	10/5
UNIT LOAD	MW	434	422	429	427	424	429	417	426	356	358	253	265
FLOWS	KG/S												
FEEDWATER (MEASURED)		364	370	370	372	377	367	374	377	299	299	218	216
AUXILIARY STEAM - SH (PLANT INSTRUMENTATION)		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
SH SPRAY (HEAT BALANCE)		0	0	0	0	0	0	0	0	0	0	0	1
MAIN STEAM (CALCULATED)		364	370	370	372	377	367	374	377	299	299	218	217
TURBINE LEAKAGE (TURBINE HEAT BALANCE)		7	7	7	7	7	7	7	7	6	6	5	3
HP 4TH. EXTRACTION (HEAT BALANCE)		30	32	31	32	32	31	31	32	23	23	15	15
RH SPRAY (HEAT BALANCE)		4	1	0	3	5	5	0	0	0	2	0	0
RH STEAM (CALCULATED)		331	332	332	336	342	334	335	338	270	272	199	197
UNIT ABSORPTION	MJ/S												
ECONOMIZER		169	158	163	166	161	166	155	157	119	130	87	91
FURNACE		339	361	356	356	367	348	369	370	323	311	261	251
DRUM - SH DESH		155	145	148	148	147	151	142	143	109	120	73	78
SH DESH - SH OUTLET		182	145	181	180	176	181	183	184	151	144	108	114
REHEATER		176	166	172	173	175	178	177	170	140	147	107	105
TOTAL		1022	1005	1019	1023	1026	1023	1025	1024	842	853	634	638
UNIT EFFICIENCY	%												
DRY GAS LOSS		4.21	3.74	4.18	4.13	4.06	4.09	4.09	4.02	3.71	3.50	3.02	3.32
MOISTURE IN FUEL LOSS		5.10	4.97	5.05	5.05	5.05	5.12	5.05	5.04	4.98	4.95	4.95	4.95
MOISTURE IN AIR LOSS		0.13	0.11	0.13	0.13	0.12	0.13	0.13	0.12	0.11	0.11	0.09	0.10
RADIATION LOSS		0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.23	0.22	0.30	0.30
ASH PIT LOSS		0.32	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.32	0.34	0.32
HEAT IN FLY ASH LOSS		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01
PYRITE REJECTION LOSS		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01
CARBON LOSS		0.21	0.30	0.28	0.26	0.22	0.63	0.40	0.43	0.20	0.22	0.47	0.22
TOTAL LOSSES		10.17	9.68	10.18	10.10	9.99	10.49	10.21	10.15	9.59	9.35	9.21	9.24
EFFICIENCY		89.83	90.32	89.82	89.90	90.01	89.51	89.79	89.85	90.41	90.65	90.79	90.76
HEAT INPUT	MJ/S												
HEAT INPUT FROM FUEL		1137	1113	1135	1138	1140	1143	1142	1140	931	941	698	703
EXCESS AIR	%												
AIR HEATER INLET		25.1	22.0	25.1	21.3	23.5	21.7	18.5	19.6	19.3	21.5	22.8	23.9
AIR HEATER OUTLET		36.7	29.9	31.8	31.4	33.6	31.6	32.8	35.1	39.6	37.4	34.8	36.7

SHEET 821

OVERFIRE AIR OPERATION STUDY

TEST RESULTS

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12
DATE	1975	9/17	9/26	9/26	9/26	9/26	10/1	10/1	10/1	9/27	10/1	10/1	10/5
UNIT LOAD	MW	428	430	430	430	431	430	429	428	428	429	430	427
PRODUCTS OF COMBUSTION	MG/J												
AIR HEATER INLET													
DRY AIR		479	417	427	433	421	416	422	411	477	503	478	412
WET AIR		487	424	434	440	428	423	429	417	485	511	486	419
DRY PRODUCTS		427	419	418	415	411	394	399	396	437	439	440	406
WET PRODUCTS		454	446	445	441	437	420	425	421	464	466	467	432
AIR HEATER OUTLET													
DRY AIR		414	406	406	401	397	381	386	383	424	426	427	392
WET AIR		421	412	412	408	404	387	393	389	432	434	434	399
DRY PRODUCTS		492	430	440	447	434	428	434	423	490	516	490	426
WET PRODUCTS		519	457	466	473	461	455	461	450	517	543	518	452
GAS AND AIR FLOWS	KG/S												
GAS ENTERING AIR HEATER		517	509	509	504	498	479	486	476	526	530	532	488
GAS LEAVING AIR HEATER		592	522	534	541	525	520	527	508	586	618	590	510
AIR ENTERING AIR HEATER		555	484	497	504	488	483	490	472	549	582	553	473
AIR LEAVING AIR HEATER		480	471	472	466	460	442	449	440	489	494	495	451
AIR HEATER LEAKAGE		75	13	25	37	27	40	41	32	60	88	58	22
AIR HEATER PERFORMANCE													
AIR HEATER LEAKAGE	%	14.5	2.6	4.9	7.4	5.5	8.4	8.5	6.7	11.4	16.7	10.9	4.6
GAS SIDE EFFICIENCY	%	67.2	69.1	68.5	68.3	68.7	68.2	68.2	70.5	66.9	65.8	67.2	68.2
GAS DROP	°C	212	210	209	208	210	210	209	216	208	208	213	210
AIR RISE	°C	243	241	241	239	241	242	241	242	241	245	246	242
TEMPERATURE HEAD	°C	316	304	306	304	306	309	307	307	311	316	317	309
FUEL ANALYSIS													
CARBON	%	65.40	63.70	65.90	63.90	65.10	66.20	67.20	67.50	66.80	63.90	67.00	66.60
HYDROGEN	%	5.10	4.90	5.20	4.80	5.00	5.20	5.30	5.30	5.20	4.90	5.20	5.10
NITROGEN	%	1.10	1.30	1.20	1.20	1.30	1.20	1.30	1.20	1.10	1.20	1.30	1.30
OXYGEN	%	9.40	10.20	9.50	9.70	10.40	9.50	9.60	9.70	9.70	9.00	9.70	10.60
SULFUR	%	0.50	0.50	0.40	0.40	0.40	0.50	0.40	0.40	0.50	0.40	0.50	0.50
MOISTURE	%	7.40	9.40	8.30	8.30	8.70	8.30	7.80	8.00	8.50	7.80	8.40	7.70
ASH	%	11.10	10.00	9.50	11.70	9.10	9.10	8.50	7.90	8.20	12.80	7.90	8.20
HHV	KJ/KG	27214	27121	27889	26842	27586	27982	28098	28540	28191	27121	28447	28098

OVERFIRE AIR OPERATION STUDY

TEST RESULTS

TEST NO.		13	14	15	16	17	18	19	20	21	22	23	24
DATE	1975	10/4	10/5	10/4	10/3	10/3	10/3	10/6	10/8	10/9	10/9	10/12	10/5
UNIT LOAD	MW	434	422	429	427	424	429	417	426	356	358	253	265
PRODUCTS OF COMBUSTION	MJ/J												
AIR HEATER INLET													
DRY AIR		437	412	427	424	428	429	430	435	442	443	432	442
WET AIR		444	419	434	431	436	436	437	442	450	450	440	449
DRY PRODUCTS		412	400	419	404	409	410	396	398	391	404	406	414
WET PRODUCTS		439	426	446	430	435	437	422	424	417	430	433	440
AIR HEATER OUTLET													
DRY AIR		400	487	406	391	396	397	383	385	378	391	394	401
WET AIR		407	393	412	398	403	403	390	391	384	398	401	408
DRY PRODUCTS		450	425	441	436	441	443	442	448	456	455	445	455
WET PRODUCTS		477	451	468	463	468	470	469	475	482	482	472	482
GAS AND AIR FLOWS	KG/S												
GAS ENTERING AIR HEATER		499	474	506	489	496	499	482	483	388	405	302	309
GAS LEAVING AIR HEATER		542	502	531	527	534	537	536	541	449	454	330	339
AIR ENTERING AIR HEATER		505	466	493	490	497	499	499	504	419	424	307	316
AIR LEAVING AIR HEATER		462	438	468	453	459	461	445	446	358	375	280	287
AIR HEATER LEAKAGE		43	28	25	38	38	38	54	58	61	49	27	30
AIR HEATER PERFORMANCE													
AIR HEATER LEAKAGE	%	8.6	6.0	4.9	7.7	7.6	7.5	11.2	12.0	15.7	12.1	9.0	9.5
GAS SIDE EFFICIENCY	%	67.7	69.7	68.0	67.4	67.9	68.2	66.7	67.3	66.6	69.9	69.5	68.5
GAS DROP	°C	211	213	210	209	207	212	204	204	185	197	167	172
AIR RISE	°C	243	239	241	243	239	242	239	237	222	220	196	202
TEMPERATURE HEAD	°C	311	306	308	310	305	310	305	303	277	282	240	251
FUEL ANALYSIS													
CARBON	%	67.20	64.00	65.90	68.40	66.90	67.20	67.40	66.70	65.00	67.20	67.20	67.30
HYDROGEN	%	5.30	5.00	5.10	5.40	5.20	5.20	5.30	5.20	5.00	5.30	5.30	5.30
NITROGEN	%	1.40	1.30	1.10	1.20	1.20	1.20	1.20	1.20	1.30	1.40	1.30	1.30
OXYGEN	%	9.60	10.30	10.50	9.80	9.70	10.80	9.70	9.70	10.40	9.70	9.60	9.70
SULFUR	%	0.50	0.50	0.50	0.40	0.50	0.50	0.50	0.40	0.50	0.50	0.40	0.40
MOISTURE	%	8.60	8.10	7.50	7.50	8.40	8.00	7.50	8.00	8.90	7.60	8.30	7.60
ASH	%	7.40	9.90	9.40	7.30	8.10	7.10	8.40	8.80	8.90	8.30	7.90	8.40
HHV	J/KG	28610	27560	27400	28842	28284	27703	28284	28052	27633	28377	28424	28284

BASELINE OPERATION STUDY

BOARD AND COMPUTER DATA

	TEST NO.		1	2	2A	3	4	5	6	7	8	9
	DATE	1975	5/7	5/5	5/7	5/7	10/10	7/16	7/15	7/16	5/5	4/30
	TIME		09:25	17:23	16:50	14:15	03:30	11:30	15:05	15:45	13:40	15:07
C*	LOAD	MW	429	427	428	428	360	259	260	258	430	428
	FLOWS	10^3LB/HR										
C	FEEDWATER		2913	2945	2910	2912	2249	1535	1520	1503	2900	2898
B*	MAIN STEAM		3050	3000	3050	3000	2350	1525	1520	1502	3040	3000
C	SUPERHEAT SPRAY L		0	0	0	0	14.1	10.2	23.2	31.5	0	0
C	SUPERHEAT SPRAY R		0	0	0	0	12.0	1.4	13.5	21.9	0	0
C	REHEAT SPRAY		0	0	0	0	7.1	0	0	0	16.5	0
C	EXT. STM. TO STM. AH 2-1		58.9	58.9	58.9	58.9	58.8	13.3	9.3	18.5	58.9	58.9
C	EXT. STM. TO STM. AH 2-2		58.9	58.9	58.9	58.9	58.8	13.25	9.2	18.5	58.9	58.9
C	AUX. STM. TO STM. AH 2-1		0	0	0	0	1.2	0	0	0	0	0
C	AUX. STM. TO STM. AH 2-2		0	0	0	0	1.2	0	0	0	0	0
C	AUX. STEAM TO STAE		3.1	3.1	3.1	3.1	3.1	3.0	3.0	3.0	3.1	3.0
B	AIR FLOW TO BOILER		3240	3350	3510	3820	2720	1700	1750	2200	3140	3380
	PRESSURES											
	STEAM & WATER	PSIG										
C	FEEDWATER TO ECON.		2825	2810	2825	2825	2689	2532	2515	2523	2818	2811
C	BOILER DRUM		2737	2719	2740	2737	2615	2485	2473	2481	2724	2723
C	TURBINE THROTTLE		2449	2441	2452	2450	2406	2385	2374	2384	2445	2435
C	TURBINE 1ST STAGE		1841	1834	1841	1841	1435	939	938	935	1841	1832
C	RH INLET, LEFT		572	568	570	570	465	311	313	311	574	569
C	RH INLET, RIGHT		576	572	574	574	469	314	314	312	578	573
C	RH INLET, AVG.		574	570	572	572	467	313	314	312	576	571
C	RH OUTLET		533	529	530	530	429	278	279	278	534	528
C	HP HTR. 2-7 STEAM IN		550	548	550	548	382	412	412	412	553	548
	AIR & GAS	"H_2O										
B	FD FAN 2-1 DISCHARGE R		8.4	9.6	11.6	12.9	8.2	4.0	4.5	6.6	9.6	9.9
B	FD FAN 2-2 DISCHARGE L		8.6	9.6	11.6	12.9	8.2	3.9	4.5	6.6	9.6	9.9
B	FD FAN DISCHARGE AVG.		8.5	9.6	11.6	12.9	8.2	4.0	4.5	6.6	9.6	9.9
C	AH 2-1 AIR DIFF. PRESS. R		3.5	3.7	4.1	4.6	2.7	1.19	1.26	1.77	3.5	3.8
C	AH 2-2 AIR DIFF. PRESS. L		3.6	3.9	4.2	4.8	3.1	1.37	1.45	1.88	3.6	3.9
C	AH AIR DIFF. PRESS. AVG.		3.6	3.8	4.2	4.7	2.9	1.28	1.36	1.83	3.6	3.9
B	WINDBOX PRESSURE R		3.2	3.5	5.5	5.7	4.1	2.2	2.5	3.9	4.5	4.3
B	WINDBOX PRESSURE L		3.3	3.6	5.5	5.7	4.1	2.2	2.5	3.9	4.5	4.3
B	WINDBOX PRESSURE AVG.		3.3	3.6	5.5	5.7	4.1	2.2	2.5	3.9	4.5	4.3
B	FURNACE DRAFT		-0.5	-0.6	-0.5	-0.5	-1.0	NA	-0.6	-0.4	-0.6	-0.4
C	SH DRAFT DIFF.		1.80	2.10	2.12	2.43	1.6	0.32	0.46	0.64	1.82	1.96
C	ECON. DRAFT DIFF.		2.28	2.52	2.78	3.06	1.98	0.65	0.67	1.05	2.23	2.47
B	AH 2-1 GAS OUT PRESS. R		-12.7	-13.3	-15.0	-15+	-10.4	-5.6	-5.4	-6.8	-12.5	-13.0
B	AH 2-2 GAS OUT PRESS. L		-11.5	-12.6	-13.5	-15+	-11.2	-5.1	-5.1	-6.2	-11.4	-12.0
B	AH GAS OUT PRESSURE AVG.		-12.1	-13.0	-14.2	-15+	-10.8	-5.4	-5.3	-6.5	-12.0	-12.5
B	ID FAN 2-1 INLET PRESS. R		-15.6	-16.6	-18.4	-20.0	-13.1	-6.8	-7.1	-8.0	-15.6	-16.3
B	ID FAN 2-2 INLET PRESS. L		-13.5	-15.0	-16.1	-17.7	-11.1	-5.4	-5.7	-7.2	-13.5	-14.8
B	ID FAN INLET PRESSURE AVG.		-14.6	-15.8	-17.3	-18.9	-12.1	-6.1	-6.4	-7.6	-14.6	-15.6

* C = COMPUTER DATA; B = BOARD DATA

BASELINE OPERATION STUDY

BOARD AND COMPUTER DATA

TEST NO.		10	11	12	13	14	15	16	17	18	19
DATE	1975	5/1	7/17	7/18	5/9	5/9	5/9	10/9	7/22	7/21	7/21
TIME		17:50	11:15	10:00	15:30	10:15	18:15	03:00	11:15	16:30	14:00
C* LOAD	MW	428	256	259	433	433	433	361	258	260	258
FLOWS	10^3LB/HR										
C FEEDWATER		2895	1517	1482	2930	2915	2905	2058	1571	1573	1529
B* MAIN STEAM		3050	1504	1503	3038	3012	3012	2350	1508	1532	1505
C SUPERHEAT SPRAY L		0	20.7	33.0	0	0	0	4.4	0	9.8	26.3
C SUPERHEAT SPRAY R		0	13.0	25.6	0	0	0	1.2	0	2.5	19.2
C REHEAT SPRAY		0	0	0	27.5	31.0	27.3	22.7	0	0	0
C EXT. STM. TO STM. AH 2-1		58.9	14.2	19.1	58.9	58.9	58.9	58.8	7.2	8.4	12.0
C EXT. STM. TO STM. AH 2-2		58.9	14.3	19.3	58.9	58.9	58.9	58.8	7.3	8.5	12.1
C AUX. STM. TO STM. AH 2-1		0	0	0	0	0	0	1.2	0	0	0
C AUX. STM. TO STM. AH 2-2		0	0	0	0	0	0	1.2	0	0	0
C AUX. STEAM TO STAE		3.0	3.0	3.0	3.0	3.0	3.0	3.1	3.0	3.0	3.0
B AIR FLOW TO BOILER		3720	1700	2100	2980	3120	3620	2720	1660	1710	2020
PRESSURES											
STEAM AND WATER	PSIG										
C FEEDWATER TO ECON.		2812	2513	2143	2828	2826	2826	2699	2537	2504	2501
C BOILER DRUM		2725	2472	2108	2738	2738	2737	2623	2492	2458	2458
C TURBINE THROTTLE		2438	2374	1978	2453	2456	2454	2417	2363	2359	2362
C TURBINE 1ST STAGE		1834	931	952	1846	1845	1845	1430	932	931	926
C RH INLET, LEFT		568	310	313	579	577	575	466	310	311	309
C RH INLET, RIGHT		571	311	314	583	581	579	468	311	315	311
C RH INLET, AVG.		570	311	314	581	579	577	467	311	313	310
C RH OUTLET		528	278	280	539	538	536	423	278	279	277
C HP HTR. 2-7 STEAM IN		546	409	412	556	556	554	385	412	409	412
AIR AND GAS	"H_2O										
B FD FAN 2-1 DISCHARGE R		12.0	3.8	6.4	8.2	9.0	11.5	8.8	3.4	3.2	5.6
B FD FAN 2-2 DISCHARGE L		12.0	3.7	6.4	8.2	9.0	11.6	8.5	3.4	3.2	5.2
B FD FAN DISCHARGE AVG.		12.0	3.8	6.4	8.2	9.0	11.6	8.6	3.4	3.2	5.4
C AH 2-1 AIR DIFF. PRESS. R		4.4	1.21	1.73	3.1	3.4	4.2	2.6	1.18	1.22	1.60
C AH 2-2 AIR DIFF. PRESS. L		4.6	1.38	1.83	3.3	3.5	4.4	3.0	1.37	1.42	1.75
C AH AIR DIFF. PRESS. AVG.		4.5	1.30	1.78	3.2	3.5	4.3	2.8	1.28	1.32	1.68
B WINDBOX PRESSURE R		4.8	1.8	3.9	3.6	3.7	5.0	4.6	1.5	1.7	2.8
B WINDBOX PRESSURE L		4.8	1.8	3.9	3.6	3.7	5.0	4.6	1.5	1.7	2.8
B WINDBOX PRESSURE AVG.		4.8	1.8	3.9	3.6	3.7	5.0	4.6	1.5	1.7	2.8
B FURNACE DRAFT		-0.5	-0.7	-0.5	-0.5	-0.6	-0.6	-1.0	-0.4	-0.6	-0.6
C SH DRAFT DIFF.		2.28	0.38	0.5	1.54	1.64	2.19	1.45	0.39	0.38	0.67
C ECON. DRAFT DIFF.		2.95	0.75	1.04	2.0	2.27	2.90	1.89	0.59	0.84	0.94
B AH 2-1 GAS OUT PRESS. R		-15+	-5.2	-6.5	-12.0	-13.1	-15+	-10.3	-5.2	-5.6	-6.5
B AH 2-2 GAS OUT PRESS. L		-15+	-4.8	-5.8	-10.9	-12.1	-15+	-10.1	-4.5	-5	-5.9
B AH GAS OUT PRESSURE AVG.		-15+	-5.0	-6.2	-11.5	-12.6	-15+	-10.2	-4.9	-5.3	-6.2
B ID FAN 2-1 INLET PRESS. R		-18.9	-6.8	-8.2	-14.6	-16.1	-18.8	-12.1	-6.4	-6.9	-8.1
B ID FAN 2-2 INLET PRESS. L		-17.5	-5.4	-6.5	-12.5	-13.6	-16.0	-11.0	-5.1	-5.5	-6.4
B ID FAN INLET PRESSURE AVG.		-18.2	-6.1	-7.4	-13.6	-14.9	-17.4	-11.6	-5.8	-6.2	-7.3

* C = COMPUTER DATA; B = BOARD DATA

BASELINE OPERATION STUDY

BOARD AND COMPUTER DATA

	TEST NO.		1	2	2A	3	4	5	6	7	8	9
	Date	1975	5/7	5/5	5/7	5/7	10/10	7/16	7/15	7/16	5/5	4/30
	Time		09:25	17:23	16:50	14:15	03:30	11:30	15:05	15:45	13:40	15:07
C	Load	MW	429	427	428	428	360	259	260	258	430	428
	TEMPERATURES											
	Air and Gas	°F										
C	AH 2-1 Air In		99	96	97	94	106	104	106	102	96	96
C	AH 2-2 Air In		87	88	87	88	106	103	110	98	88	89
C	AH Avg. Air In		94	92	92	91	106	104	108	100	92	93
C	AH 2-1 Air Out		499	504	503	504	510	466	471	466	506	505
C	AH 2-2 Air Out		526	528	533	534	520	470	478	480	530	528
C	AH Avg. Air Out		512	516	518	519	515	468	475	473	518	516
C	AH 2-1 Gas In		6[illegible]3	700	714	718	680	589	599	614	700	704
C	AH 2-2 Gas In		700	706	722	733	675	583	592	612	708	710
C	AH Avg. Gas In		69[illegible]	703	718	726	678	586	596	613	704	707
C	AH 2-1 Gas Out		253	257	257	260	265	245	244	240	256	258
C	AH 2-2 Gas Out (1)		NA	NA	NA	NA	268	NA	NA	NA	NA	NA
C	AH Avg. Gas Out		253	257	257	260	266	245	244	240	256	258
	Steam and Water	°F										
C	FW In Temp. to Econ.		484	484	484	484	465	428	428	428	485	484
C	Econ. Out Avg.		575	579	586	592	551	493	499	508	576	581
C	Boiler Downcomer		678	678	679	679	672	666	664	665	678	677
C	SH DESH Inlet L		739	741	748	759	757	738	750	767	743	743
C	SH DESH Inlet R		739	751	748	753	763	736	746	759	750	748
C	SH DESH Inlet Avg.		739	746	748	756	760	737	748	763	747	746
C	SH DESH Outlet L		744	747	753	759	753	730	741	734	748	748
C	SH DESH Outlet R		742	748	752	757	757	734	735	740	748	751
C	SH DESH Outlet Avg.		743	748	753	758	755	732	738	737	748	750
C	SH Outlet		982	982	988	991	1010	1008	1003	1000	991	986
C	Throttle Steam		971	976	978	980	999	999	995	996	980	975
C	RH Turbine L		613	617	618	620	601	552	550	551	623	616
C	RH Turbine R		614	617	618	620	606	562	560	560	622	617
C	RH Turbine Avg.		614	617	618	620	603	557	555	556	623	617
C	RH Boiler L		611	610	616	617	584	550	547	549	604	615
C	RH Boiler R		609	607	614	616	582	558	556	556	594	612
C	RH Boiler Avg.		610	609	615	617	583	554	552	553	599	614
C	RH Outlet		1003	1000	1002	1002	1021	981	992	992	1003	1002
C	HP Htr. 2-7 Steam In		611	616	616	620	602	558	555	556	620	616
C	HP Htr. 2-7 FW In		413	413	413	413	400	368	369	368	413	412
C	HP Htr. 2-7 Drain		423	422	423	423	406	372	372	371	423	422
C	Aux. Steam Temp.		545	549	558	562	550	567	556	578	552	556
	Fan Damper Position	% Open										
B	FD Fans		68	70	75	80	65	46	48	56	68	72
B	ID Fans		62	63	65	72	58	38	40	46	61	62
	Spray Valve Position	% Open										
B	SH Spray		0	0	0	0	11	11	23	31	0	0
B	RH Spray		0	0	0	0	0	0	0	0	21	0

C = Computer Data; B = Board Data
(1) TC Reading Open

BASELINE OPERATION STUDY

BOARD AND COMPUTER DATA

	TEST NO.		10	11	12	13	14	15	16	17	18	19
	DATE	1975	5/1	7/17	7/18	5/9	5/9	5/9	10/9	7/22	7/21	7/21
	TIME		17:50	11:15	10:00	15:30	10:15	18:15	03:00	11:15	16:30	14:00
C	LOAD	MW	428	256	259	433	433	433	361	258	260	258
	TEMPERATURES											
	AIR AND GAS	°F										
C	AH 2-1 AIR IN		93	104	104	96	97	92	109	104	103	104
C	AH 2-2 AIR IN		89	112	105	88	86	87	112	112	112	101
C	AH AVG. AIR IN		91	108	105	92	92	89	110	108	108	103
C	AH 2-1 AIR OUT		506	470	465	510	508	514	508	470	473	473
C	AH 2-2 AIR OUT		531	473	480	532	533	538	514	476	477	484
C	AH AVG. AIR OUT		518	472	473	521	520	526	511	473	475	479
C	AH 2-1 GAS IN		719	596	617	699	703	728	677	599	602	618
C	AH 2-2 GAS IN		717	586	611	704	709	722	679	597	596	614
C	AH AVG. GAS IN		718	591	614	702	706	725	678	598	599	616
C	AH 2-1 GAS OUT		260	246	237	257	257	262	262	244	246	244
C	AH 2-2 GAS OUT (1)		NA	NA	NA	NA	NA	NA	260	NA	NA	NA
C	AH AVG. GAS OUT		260	246	237	257	257	262	261	244	246	244
	STEAM AND WATER	°F										
C	FW IN TEMP. TO ECON.		484	428	429	485	485	485	465	426	427	427
C	ECON. OUT AVG.		591	495	503	575	579	593	548	494	496	505
C	BOILER DOWNCOMER		679	664	642	678	679	679	673	665	663	663
C	SH DESH INLET L		749	747	763	744	746	760	758	744	745	765
C	SH DESH INLET R		754	744	758	745	748	763	767	739	746	766
C	SH DESH INLET AVG.		752	746	761	745	747	762	762	742	746	766
C	SH DESH OUTLET L		754	730	724	750	751	765	761	746	739	740
C	SH DESH OUTLET R		758	734	729	750	752	768	767	747	744	745
C	SH DESH OUTLET AVG.		756	732	727	750	752	767	764	747	742	743
C	SH OUTLET		992	1006	1005	985	991	997	1014	1001	1002	1004
C	THROTTLE STEAM		982	996	998	974	981	987	1004	993	993	996
C	RH TURBINE L		621	551	581	619	623	628	605	547	548	550
C	RH TURBINE R		622	561	600	619	624	628	610	557	559	562
C	RH TURBINE AVG.		622	556	591	619	624	628	608	552	554	556
C	RH BOILER L		618	548	574	576	573	591	553	544	547	548
C	RH BOILER R		617	556	591	570	572	582	545	552	556	557
C	RH BOILER AVG.		618	552	583	573	573	587	549	548	565	553
C	RH OUTLET		1000	1001	1001	1003	1002	1004	1018	1000	1000	1001
C	HP HTR. 2-7 STEAM IN		618	556	585	618	621	626	608	552	555	556
C	HP HTR. 2-7 FW IN		412	368	369	414	414	414	400	368	368	368
C	HP HTR. 2-7 DRAIN		422	371	369	424	424	424	406	372	371	372
C	AUX. STEAM TEMP.		563	567	606	548	556	564	563	572	565	567
	FAN DAMPER POSITION	% OPEN										
B	FD FANS		78	45	56	68	70	76	63	45	47	54
B	ID FANS		69	39	46	59	63	67	55	38	40	43
	SPRAY VALVE POSITION	% OPEN										
B	SH SPRAY		0	22	35	0	0	0	0	0	8	28
B	RH SPRAY		0	0	0	30	35	30	26	0	0	0

C = COMPUTER DATA; B = BOARD DATA
(1) TC READING OPEN

BASELINE OPERATION STUDY

BOARD AND COMPUTER DATA

	TEST NO.		1	2	2A	3	4	5	6	7	8	9
	DATE	1975	5/7	5/5	5/7	5/7	10/10	7/16	7/15	7/16	5/5	4/30
	TIME		09:25	17:23	16:50	14:15	03:30	11:30	15:05	15:45	13:40	15:07
C	LOAD	MW	429	427	428	428	360	259	260	258	430	428
	MILL DATA											
C	MILL 2-1	AMPS	92	91	92	92	NA	81	81	81	90	90
C	MILL 2-2	AMPS	93	96	94	93	NA	81	79	81	95	87
C	MILL 2-3	AMPS	88	88	88	89	NA	80	82	80	88	92
C	MILL 2-4	AMPS	88	89	89	89	NA	80	82	82	88	91
C	MILL 2-5	AMPS	87	89	87	87	NA	0	0	0	88	90
C	COAL AIR TEMP. MILL 2-1	°F	148	149	148	148	148	147	147	147	148	149
C	COAL AIR TEMP. MILL 2-2	°F	148	146	147	147	148	147	147	147	147	148
C	COAL AIR TEMP. MILL 2-3	°F	147	147	147	147	148	148	148	148	147	147
C	COAL AIR TEMP. MILL 2-4	°F	147	147	147	147	146	146	146	146	147	147
C	COAL AIR TEMP. MILL 2-5	°F	149	149	150	149	149	85	90	85	150	150
B	MILL 2-1 EXH. DISCHARGE	"H_2O	8.3	8.1	8.4	8.5	7.0	7.1	6.5	6.2	8.0	8.5
B	MILL 2-2 EXH. DISCHARGE	"H_2O	7.6	7.8	7.9	7.9	6.4	6.3	6.2	6.5	7.8	7.5
B	MILL 2-3 EXH. DISCHARGE	"H_2O	7.1	7.0	7.5	7.4	6.8	7.0	7.4	7.1	7.0	7.8
B	MILL 2-4 EXH. DISCHARGE	"H_2O	6.9	7.1	7.2	7.0	7.1	6.2	6.5	6.5	7.2	7.4
B	MILL 2-5 EXH. DISCHARGE	"H_2O	7.3	7.2	7.3	7.3	6.6	0	0	0	7.6	7.8
B	MILL 2-1 SUCTION	"H_2O	-1.76	-1.8	-1.6	-1.3	-2.0	-2.3	-2.5	-2.0	-1.8	-1.7
B	MILL 2-2 SUCTION	"H_2O	-1.6	-1.5	-1.4	-1.3	-2.2	-2.2	-2.5	-2.1	-1.5	-1.8
B	MILL 2-3 SUCTION	"H_2O	-1.86	-1.9	-1.6	-1.5	-1.95	-2.1	-2.2	-2.0	-1.8	-1.8
B	MILL 2-4 SUCTION	"H_2O	-2.0	-1.9	-1.8	-1.8	-2.0	-2.5	-2.4	-2.2	-1.8	-1.8
B	MILL 2-5 SUCTION	"H_2O	-2.0	-2.0	-1.8	-1.6	-2.25	0	0	0	-1.8	-1.8
B	MILL 2-1 COAL FLOW	10^3LB/HR	70	63	69	70	58	48	43	48	63	65
B	MILL 2-2 COAL FLOW	10^3LB/HR	62	60	61	61	48	44	40	44	60	65
B	MILL 2-3 COAL FLOW	10^3LB/HR	61	60	61	61	58	43	47	44	59	63
B	MILL 2-4 COAL FLOW	10^3LB/HR	61	60	60	61	58	46	48	44	60	64
B	MILL 2-5 COAL FLOW	10^3LB/HR	62	60	62	62	59	0	0	0	62	65
B	MILL 2-1 FEEDER SPEED (1)	%	80	73	78	80	67	56	48	56	73	75
B	MILL 2-2 FEEDER SPEED	%	74	72	74	74	56	52	48	54	72	78
B	MILL 2-3 FEEDER SPEED	%	72	71	72	73	69	52	57	54	71	77
B	MILL 2-4 FEEDER SPEED	%	74	71	74	75	69	53	58	54	72	78
B	MILL 2-5 FEEDER SPEED	%	74	73	74	75	70	0	0	0	74	79
	BURNER TILT	± DEGREES										
B	POSITION LF		14	13	12	14	0	16	10	4	10	NA
B	POSITION LR		14	12	13	15	1	16	10	6	8	NA
B	POSITION RF		15	13	14	15	0	18	10	6	10	NA
B	POSITION RR		18	12	13	15	0	18	10	5	8	NA
	MISCELLANEOUS											
B	DRUM LEVEL, IN. ± NORM. H_2O LEVEL		0	0	0	0	0	-1.0	-1.0	-1.0	0	0
C	FD FAN 2-1	AMPS	224	231	247	262	201	173	175	190	227	232
C	FD FAN 2-2	AMPS	212	216	227	238	216	171	173	185	213	216
C	ID FAN 2-1	AMPS	378	392	406	437	360	307	311	330	379	392
C	ID FAN 2-2	AMPS	379	389	406	430	364	307	311	328	378	388
C	FLUE GAS SO_2 IN STACK	PPM	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
C	FLUE GAS COMBUSTIBLES L	%	0	0	0	0	.10	0	0	0	0	0
C	FLUE GAS COMBUSTIBLES R	%	0	0	0	0	.05	0	0	0	0	0
C	FLUE GAS O_2 L	%	3.01	4.24	4.37	5.65	4.26	2.75	3.46	5.31	2.69	4.45
C	FLUE GAS O_2 R	%	3.08	3.96	4.88	5.96	3.83	3.62	4.33	6.44	3.20	3.36
C	FLUE GAS O_2 AVG.	%	3.05	4.10	4.63	5.81	4.04	3.19	3.90	5.88	2.95	3.91
B	AMBIENT TEMP.	°F	37	33	45	43	39	72	78	62	40	54
B	AMBIENT REL. HUMIDITY	%	63	62	51	58	56	62	52	63	48	44
B	BAROMETRIC PRESSURE	"Hg	23.59	23.48	23.66	23.65	23.94	23.85	23.85	23.81	23.43	23.73

C = COMPUTER DATA; B = BOARD DATA
(1) FEEDER SPEED IN % OF CONTROL SIGNAL.

BASELINE OPERATION STUDY

BOARD AND COMPUTER DATA

	TEST NO.		10	11	12	13	14	15	16	17	18	19
	DATE	1975	5/1	7/17	7/18	5/9	5/9	5/9	10/9	7/22	7/21	7/21
	TIME		17:50	11:15	10:00	15:30	10:15	18:15	03:00	11:15	16:30	14:00
C	LOAD	MW	428	256	259	433	433	433	361	258	260	258
	MILL DATA											
C	MILL 2-1	AMPS	91	79	81	91	91	92	NA	80	80	80
C	MILL 2-2	AMPS	89	80	76	96	95	96	NA	0	0	0
C	MILL 2-3	AMPS	91	81	84	90	89	89	NA	78	81	81
C	MILL 2-4	AMPS	91	82	80	88	89	89	NA	80	81	82
C	MILL 2-5	AMPS	91	0	0	89	90	90	NA	82	83	83
C	COAL AIR TEMP. MILL 2-1	°F	149	146	147	149	149	149	149	147	147	147
C	COAL AIR TEMP. MILL 2-2	°F	147	146	147	148	148	147	148	86	85	86
C	COAL AIR TEMP. MILL 2-3	°F	147	148	149	148	148	147	147	148	149	148
C	COAL AIR TEMP. MILL 2-4	°F	147	145	146	147	147	147	78	146	146	146
C	COAL AIR TEMP. MILL 2-5	°F	150	86	87	149	150	150	149	149	149	148
B	MILL 2-1 EXH. DISCHARGE	"H_2O	8.5	5.9	5.7	8.3	8.1	8.2	7.4	5.8	5.6	5.9
B	MILL 2-2 EXH. DISCHARGE	"H_2O	7.6	6.4	9.5	8.0	8.0	8.3	6.5	0	0	0
B	MILL 2-3 EXH. DISCHARGE	"H_2O	7.8	7.8	10.1	7.0	7.2	7.4	6.9	7.3	7.4	7.5
B	MILL 2-4 EXH. DISCHARGE	"H_2O	7.9	6.5	7	7.1	7.4	7.2	0	6.5	6.9	6.8
B	MILL 2-5 EXH. DISCHARGE	"H_2O	8.0	0	0	7.6	7.3	7.6	7.0	6.9	6.8	7.0
B	MILL 2-1 SUCTION	"H_2O	-1.6	-2.2	-2.1	-1.9	-1.8	-1.8	-1.9	-2.2	-2.3	-2.2
B	MILL 2-2 SUCTION	"H_2O	-1.7	-2.3	-2.0	-1.6	-1.6	-1.5	-1.8	0	0	0
B	MILL 2-3 SUCTION	"H_2O	-1.6	-2.2	-1.7	-2.0	-1.9	-1.9	-1.7	-2.2	-2.2	-2.1
B	MILL 2-4 SUCTION	"H_2O	-1.8	-2.5	-2.1	-2.0	-2.0	-1.9	0	-2.4	-2.4	-2.3
B	MILL 2-5 SUCTION	"H_2O	-1.6	0	0	-2.0	-2.0	-1.9	-1.9	-2.3	-2.3	-2.2
B	MILL 2-1 COAL FLOW	10^3LB/HR	64	44	44	66	66	65	64	47	46	44
B	MILL 2-2 COAL FLOW	10^3LB/HR	65	44	44	62	62	62	70	0	0	0
B	MILL 2-3 COAL FLOW	10^3LB/HR	63	46	50	61	62	61	68	43	48	48
B	MILL 2-4 COAL FLOW	10^3LB/HR	64	45	53	62	62	62	0	49	49	50
B	MILL 2-5 COAL FLOW	10^3LB/HR	65	0	0	63	62	63	70	50	50	52
B	MILL 2-1 FEEDER SPEED (1)	%	74	50	52	75	76	76	74	54	53	52
B	MILL 2-2 FEEDER SPEED	%	78	54	53	75	75	75	82	0	0	0
B	MILL 2-3 FEEDER SPEED	%	78	57	61	74	74	74	80	53	58	59
B	MILL 2-4 FEEDER SPEED	%	78	53	64	75	75	75	0	59	59	60
B	MILL 2-5 FEEDER SPEED	%	79	0	0	75	74	75	83	60	60	62
	BURNER TILT	± DEGREES										
B	POSITION LF		NA	6	3	3	8	2	0	11	13	12
B	POSITION LR		NA	9	5	5	10	3	1	12	14	14
B	POSITION RF		NA	8	5	5	10	4	0	12	16	14
B	POSITION RR		NA	7	3	3	8	2	0	12	14	14
	MISCELLANEOUS											
B	DRUM LEVEL, IN. ± NORM. H_2O LEVEL		0	-1	-1	0	0	0	0	-1	-1	-1
C	FD FAN 2-1	AMPS	252	172	189	216	224	248	201	171	174	186
C	FD FAN 2-2	AMPS	230	171	184	205	210	227	217	170	172	182
C	ID FAN 2-1	AMPS	424	307	328	374	385	423	358	307	313	324
C	ID FAN 2-2	AMPS	417	306	326	372	387	417	356	307	312	324
C	FLUE GAS SO_2 IN STACK	PPM	NA	NA	NA	501	255	328	NA	NA	NA	NA
C	FLUE GAS COMBUSTIBLES L	%	0	0	0	0	0	0	.10	0	0	0
C	FLUE GAS COMBUSTIBLES R	%	0	0	0	0	0	0	.05	0	0	0
C	FLUE GAS O_2 L	%	6.32	3.14	5.74	3.80	4.88	7.36	2.55	2.77	3.17	5.21
C	FLUE GAS O_2 R	%	4.73	3.51	6.73	1.88	3.17	4.42	4.00	3.71	3.96	6.10
C	FLUE GAS O_2 AVG.	%	5.53	3.33	6.24	2.84	4.03	5.89	3.28	3.24	3.57	5.66
B	AMBIENT TEMP.	°F	50	70	78	63	61	60	32	82	79	80
B	AMBIENT REL. HUMIDITY	%	50	67	33	43	44	42	66	41	36	41
B	BAROMETRIC PRESSURE	"Hg	23.77	23.88	23.92	23.91	23.91	23.0	23.98	23.95	23.95	23.98

C = COMPUTER DATA; B = BOARD DATA
(1) FEEDER SPEED IN % OF CONTROL SIGNAL.

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8
	DATE	1975	9/18	9/18	9/20	12/13	10/11	10/12	10/12	10/5
	TIME		17:00	17:25	13:15	14:00	16:30	15:00	10:00	21:30
C	LOAD	MW	430	426	431	356	351	360	257	271
	FLOWS	10^3LB/HR								
C	FEEDWATER		2945	2889	2871	2291	2261	2336	1648	1603
B	MAIN STEAM		3050	3030	2975	2350	2350	2400	1600	1650
C	SUPERHEAT SPRAY L		0	0	0	0	0	0	0	29.0
C	SUPERHEAT SPRAY R		0	0	0	0	0	0	0	25.6
C	REHEAT SPRAY		0	0	21.3	0	0	0	0	0
C	EXT. STM. TO STM. AH 2-1		58.8	58.8	58.8	31.0	14.4	25.3	25.4	58.8
C	EXT. STM. TO STM. AH 2-2		58.8	58.8	58.8	36.2	14.2	25.3	25.5	58.8
C	AUX. STM. TO STM. AH 2-1		0	0	0	0	0	0	0	0
C	AUX. STM. TO STM. AH 2-2		0	0	0	0	0	0	0	0
C	AUX. STM. TO SJAE		3.0	3.0	3.0	2.0	2.9	3.0	3.0	3.0
B	AIR FLOW TO BOILER		3200	3210	3260	2510	2410	2650	1750	1850
	PRESSURES									
	STEAM AND WATER	PSIG								
C	FEEDWATER TO ECONOMIZER		2808	2814	2798	2717	2691	2694	2592	2591
C	BOILER DRUM		2713	2708	2703	2625	2624	2615	2536	2535
C	TURBINE THROTTLE		2434	2411	2417	2420	2422	2406	2416	2420
C	TURBINE 1ST STAGE		1820	1814	1816	1444	NA	NA	NA	1009
C	RH INLET, LEFT		571	568	572	462	NA	NA	NA	339
C	RH INLET, RIGHT		575	573	576	465	NA	NA	NA	340
C	RH INLET, AVERAGE		573	571	574	464	NA	NA	NA	340
C	RH OUTLET		535	532	532	422	420	436	294	306
C	HP HTR. 2-7 STM. IN		358	361	360	382	383	374	406	409
	AIR AND GAS	"H_2O								
B	FD FAN DISCHARGE R		9.5	9.6	8.6	7.1	6.3	8.4	2.8	4.0
B	FD FAN DISCHARGE L		9.5	9.6	8.5	7.0	6.3	8.4	2.8	4.0
B	FD FAN DISCHARGE AVG.		9.5	9.6	8.6	7.0	6.3	8.4	2.8	4.0
C	AH 2-1 AIR DIFF. PRESS. R		3.4	3.4	3.5	2.5	2.3	2.5	1.4	1.4
C	AH 2-2 AIR DIFF. PRESS. L		3.9	3.9	4.0	2.9	2.6	3.0	1.6	1.6
C	AH AIR DIFF. PRESS. AVG.		3.7	3.7	3.7	2.7	2.4	2.8	1.5	1.5
B	WINDBOX PRESS. R		4.0	3.9	3.3	3.5	2.8	4.4	0.6	1.5
B	WINDBOX PRESS. L		4.0	3.9	3.3	3.5	2.8	4.4	0.3	1.5
B	WINDBOX PRESS. AVG.		4.0	3.9	3.3	3.5	2.8	4.4	0.5	1.5
B	FURNACE DRAFT		-0.6	-0.6	-1.1	-1	-1	-1	-1	-1
C	SH DRAFT DIFF.		1.91	1.93	1.93	1.2	1.05	1.33	0.45	0.54
C	ECON. DRAFT DIFF.		2.37	2.37	2.50	2.21	1.65	1.83	0.92	1.05
B	AH 2-1 GAS OUT PRESS. R		-12.7	-12.6	-13.7	-10.1	-10.2	-10.5	-6.6	-6.9
B	AH 2-2 GAS OUT PRESS. L		-11.3	-11.5	-12.5	-9.1	-9.4	-9.8	-6.1	-6.9
B	AH GAS OUT PRESS. AVG.		-12.2	-12.1	-13.1	-9.6	-9.8	-10.2	-6.4	-6.9
B	ID FAN 2-1 INLET PRESS. R		-15.4	-15.6	-16.8	-12.6	-11.8	-12.2	-7.6	-7.8
B	ID FAN 2-2 INLET PRESS. L		-12.6	-12.6	-13.1	-10.1	-10.1	-10.5	-6.6	-7.1
B	ID FAN INLET PRESS. AVG.		-14.0	-14.1	-15.0	-11.4	-11.0	-11.4	-7.1	-7.5

C = COMPUTER DATA; B = BOARD DATA

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		9	10	11	12	13	14	15	16
	DATE	1975	9/19	9/18	9/18	10/11	12/13	12/13	7/23	7/24
	TIME		14:35	09:45	14:10	14:45	12:00	10:15	10:40	09:55
C	LOAD	MW	427	429	430	351	356	357	256	259
	FLOWS	10^3 LB/HR								
C	FEEDWATER		2938	2897	2882	2273	2321	2302	1557	1584
B	MAIN STEAM		3050	3000	3000	2350	2367	2350	1500	1500
C	SUPERHEAT SPRAY L		0	0	0	0	0	0	4.7	19.2
C	SUPERHEAT SPRAY R		0	0	0	0	0	0	0	9.1
C	REHEAT SPRAY		0	26.2	30.5	0	0	2.7	0	0
C	EXT. STM. TO STH. AH 2-1		58.8	58.8	58.8	58.8	44.6	43.9	6.3	9.3
C	EXT. STM. TO STH. AH 2-2		58.8	58.8	58.8	58.8	44.2	43.8	6.2	9.3
C	AUX. STM. TO STH. AH 2-1		0	0	0	0	0	0	0	0
C	AUX. STM. TO STH. AH 2-2		0	0	0	0	0	0	0	0
C	AUX. STM. TO SJAE		3.0	3.0	3.0	2.9	2.0	2.0	3.0	3.0
B	AIR FLOW TO BOILER		3400	3480	3430	2610	2730	2860	1700	1700
	PRESSURES									
	STEAM AND WATER	PSIG								
C	FEEDWATER TO ECONOMIZER		2826	2813	2805	2668	2739	2738	2536	2544
C	BOILER DRUM		2718	2721	2722	2622	2612	2625	2489	2495
C	TURBINE THROTTLE		2420	2414	2417	2397	2434	2425	2392	2397
C	TURBINE 1ST STAGE		1824	1829	1823	NA	1438	1441	927	939
C	RH INLET, LEFT		571	575	574	NA	460	460	307	312
C	RH INLET, RIGHT		576	579	579	NA	463	463	308	314
C	RH INLET, AVERAGE		574	577	577	NA	462	462	308	313
C	RH OUTLET		533	535	535	420	426	425	274	280
C	HP HTR. 2-7 STM. IN		359	359	360	383	381	381	412	406
	AIR AND GAS	"H_2O								
B	FD FAN DISCHARGE R		9.9	10.4	10.4	8.2	7.8	8.0	3.1	3.1
B	FD FAN DISCHARGE L		9.9	10.4	10.4	8.2	7.5	8.0	3.1	3.0
B	FD FAN DISCHARGE AVG.		9.9	10.4	10.4	8.2	7.6	8.0	3.1	3.1
C	AH 2-1 AIR DIFF. PRESS. R		3.6	3.8	3.8	2.6	2.94	3.02	1.3	1.2
C	AH 2-2 AIR DIFF. PRESS. L		4.2	4.3	4.3	3.0	3.38	3.51	1.4	1.4
C	AH AIR DIFF. PRESS. AVG.		3.9	4.0	4.1	2.8	3.16	3.26	1.4	1.3
B	WINDBOX PRESS. R		4.0	3.9	4.0	4.0	4.2	4.2	1.2	1.1
B	WINDBOX PRESS. L		4.0	3.9	4.0	4.0	4.2	4.2	1.2	1.1
B	WINDBOX PRESS. AVG.		4.0	3.9	4.0	4.0	4.2	4.2	1.2	1.1
B	FURNACE DRAFT		-0.8	-0.8	-0.4	-1	-1.1	-1.0	-0.5	-0.5
C	SH DRAFT DIFF.		2.11	2.06	2.11	1.25	1.48	1.38	0.40	0.48
C	ECON. DRAFT DIFF.		2.55	2.72	2.72	1.84	2.48	2.55	0.77	0.61
B	AH 2-1 GAS OUT PRESS. R		-13.9	-14.5	-13.95	-11.1	-11.6	-12.1	-5.6	-5.7
B	AH 2-2 GAS OUT PRESS. L		-12.6	-13.1	-12.0	-10.4	-10.5	-11.3	-5.1	-5.1
B	AH GAS OUT PRESS. AVG.		-13.3	-13.8	-13.3	-10.8	-11.0	-11.7	-5.4	-5.4
B	ID FAN 2-1 INLET PRESS. R		-16.8	-17.8	-17.2	-12.9	-14.3	-14.9	-6.7	-7.1
B	ID FAN 2-2 INLET PRESS. L		-13.8	-14.3	-13.7	-11.2	-11.5	-12.2	-5.4	-5.6
B	ID FAN INLET PRESS. AVG.		-15.3	-16.0	-15.4	-12.1	-12.9	-13.6	-6.1	-5.9

C = COMPUTER DATA; B = BOARD DATA

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8
	Date	1975	9/18	9/18	9/20	12/13	10/11	10/12	10/12	10/5
	Time		17:00	17:25	13:15	14:00	16:30	15:00	10:00	21:30
C	Load	MW	430	426	431	356	351	360	257	271
	TEMPERATURES									
	Air and Gas	°F								
C	AH 2-1 Air In		106	106	105	105	109	112	117	114
C	AH 2-2 Air In		99	100	98	104	108	113	118	117
C	Avg. Air In		103	103	102	104	108	112	118	116
C	AH 2-1 Air Out		520	515	516	498	511	499	472	481
C	AH 2-2 Air Out		540	537	542	502	515	507	474	482
C	Avg. Air Out		530	526	529	500	513	503	473	482
C	AH 2-1 Gas In		715	705	707	657	664	660	598	614
C	AH 2-2 Gas In		716	706	718	626	664	660	597	616
C	Avg. Gas In		716	706	713	642	664	660	598	615
C	AH 2-1 Gas Out		266	264	265	255	264	258	249	254
C	AH 2-2 Gas Out (1)		278	277	278	258	267	261	252	253
C	Avg. Gas Out		272	271	272	256	266	260	251	254
	Steam and Water	°F								
C	FW In Temp. to Econ.		484	484	485	463	462	466	430	436
C	Econ. Out Avg.		571	570	571	534	542	543	501	508
C	Boiler Downcomer		678	678	677	673	---	672	667	669
C	SH DESH Inlet L		744	744	750	733	749	744	738	751
C	SH DESH Inlet R		756	754	753	733	753	745	746	759
C	SH DESH Inlet Avg		750	748	752	733	751	745	742	755
C	SH DESH Outlet L		751	749	757	737	750	744	744	729
C	SH DESH Outlet R		759	752	755	737	758	749	750	736
C	SH DESH Outlet Avg		755	751	756	737	754	747	747	732
C	SH Outlet		967	976	995	1005	994	1006	1006	1006
C	Throttle Steam		955	964	981	998	985	996	994	999
C	RH Turbine L		599	607	621	598	NA	NA	NA	554
C	RH Turbine R		599	607	622	601	NA	NA	NA	566
C	RH Turbine Avg		599	607	622	600	NA	NA	NA	560
C	RH Boiler L		595	604	596	NA	575	592	543	551
C	RH Boiler R		595	603	585	NA	578	593	554	561
C	RH Boiler Avg		595	604	591	NA	577	593	550	556
C	RH Outlet		993	1008	1014	1001	994	1017	1000	1018
C	HP Htr 2-7 Stm. In		601	606	623	599	589	602	552	561
C	HP Htr 2-7 FW In		416	415	415	398	398	400	372	372
C	HP Htr. 2-7 Drain		424	423	424	403	404	407	376	380
C	Aux. Steam Temp.		514	508	518	571	545	546	552	533
	FAN DAMPER POSITION	% Open								
B	FD Fans		72	71	70	60	60	64	46	48
B	ID Fans		62	62	65	53	52	55	41	43
	SPRAY VALVE POSITION	% Open								
B	SH Spray		0	0	0	0	0	0	0	30
B	RH Spray		0	1	24	0	9	8	0	0

C = Computer Data; B = Board Data
(1) TC Reading Open

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		9	10	11	12	13	14	15	16
	Date	1975	9/19	9/18	9/18	10/11	12/13	12/13	7/23	7/24
	Time		14:35	09:45	14:10	14:45	12:00	10:15	10:40	09:55
C	Load	MW	427	429	430	351	356	357	256	259
	TEMPERATURES									
	Air and Gas	°F								
C	AH 2-1 Air In		105	103	104	110	100	103	102	104
C	AH 2-2 Air In		105	99	98	110	103	104	108	104
C	Avg. Air In		105	101	101	110	102	104	105	104
C	AH 2-1 Air Out		520	516	520	504	498	499	474	472
C	AH 2-2 Air Out		542	537	542	513	504	505	477	478
C	Avg. Air Out		531	527	531	509	501	502	476	475
C	AH 2-1 Gas In		719	710	717	661	671	673	602	599
C	AH 2-2 Gas In		719	707	717	662	671	639	594	589
C	Avg. Gas In		719	709	717	662	671	656	598	594
C	AH 2-1 Gas Out		268	267	267	260	254	257	248	246
C	AH 2-2 Gas Out (1)		278	276	279	265	260	259	NA	NA
C	Avg. Gas Out		273	272	273	263	257	258	248	246
	Steam and Water	°F								
C	FW In Temp. to Econ.		484	486	485	462	463	463	425	428
C	Econ. Out Avg.		574	575	576	544	539	540	494	496
C	Boiler Downcomer		678	679	678	671	674	674	665	665
C	SH DESH Inlet L		744	745	755	752	743	743	745	750
C	SH DESH Inlet R		754	751	765	754	740	740	745	751
C	SH DESH Inlet Avg		749	751	760	753	742	742	745	751
C	SH DESH Outlet L		751	753	761	753	746	744	742	735
C	SH DESH Outlet R		759	760	765	759	744	743	747	741
C	SH DESH Outlet Avg		755	757	763	756	745	744	745	738
C	SH Outlet		964	992	990	995	1000	1008	1006	1002
C	Throttle Steam		955	980	981	988	995	998	998	995
C	RH Turbine L		599	622	623	NA	596	596	552	549
C	RH Turbine R		600	622	623	NA	601	602	560	558
C	RH Turbine Avg		600	622	623	NA	598	599	549	554
C	RH Boiler L		596	588	572	584	573	590	549	547
C	RH Boiler R		596	575	566	588	582	581	556	555
C	RH Boiler Avg		596	582	569	586	578	586	553	551
C	RH Outlet		995	998	1007	1005	1000	1005	1000	1000
C	HP Htr 2-7 Stm. In		600	619	621	591	591	598	555	554
C	HP Htr 2-7 FW In		415	415	415	398	397	398	367	368
C	HP Htr 2-7 Drain		423	423	424	404	403	403	370	371
C	Aux. Steam Temp.		512	521	525	554	571	565	573	569
	FAN DAMPER POSITION	% Open								
B	FD Fans		74	75	74	66	64	65	46	46
B	ID Fans		63	65	65	57	56	58	40	40
	SPRAY VALVE POSITION	% Open								
B	SH Spray		0	0	0	0	0	0	5	16
B	RH Spray		0	30	34	0	0	3	0	0

C = Computer Data; B = Board Data
(1) TC Reading Open

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		1	2	3	4	5	6	7	8
	Date	1975	9/18	9/18	9/20	12/13	10/11	10/12	10/12	10/5
	Time		17:00	17:25	13:15	14:00	16:30	15:00	10:00	21:30
C	Load	MW	430	426	431	356	351	360	257	271
	MILL DATA									
C	Mill 2-1	AMPS	NA	NA	NA	60.3	NA	NA	NA	NA
C	Mill 2-2	AMPS	NA	NA	NA	93.0	NA	NA	NA	NA
C	Mill 2-3	AMPS	NA	NA	NA	87.4	NA	NA	NA	NA
C	Mill 2-4	AMPS	NA	NA	NA	88.0	NA	NA	NA	NA
C	Mill 2-5	AMPS	NA	NA	NA	87.6	NA	NA	NA	NA
C	Coal Air Temp. Mill 2-1	°F	154	148	148	157	149	148	75	148
C	Coal Air Temp. Mill 2-2	°F	148	154	148	149	148	148	146	112
C	Coal Air Temp. Mill 2-3	°F	147	146	147	149	88	148	146	147
C	Coal Air Temp. Mill 2-4	°F	148	148	148	148	147	97	145	145
C	Coal Air Temp. Mill 2-5	°F	149	148	147	151	150	150	149	149
B	Mill 2-1 Exh. Discharge	"H_2O	5.5	8.2	7.1	4.5	7.9	7.5	NA	7.0
B	Mill 2-2 Exh. Discharge	"H_2O	7.4	7.6	7.1	7.1	NA	6.5	6.6	6.5
B	Mill 2-3 Exh. Discharge	"H_2O	8.4	5.5	8.0	7.0	7.3	7.4	6.2	NA
B	Mill 2-4 Exh. Discharge	"H_2O	10.1	10.5	10.0	7.5	7.5	NA	6.5	6.5
B	Mill 2-5 Exh. Discharge	"H_2O	8.4	8.5	NA	7.4	7.5	6.8	6.2	6.5
B	Mill 2-1 Suction	"H_2O	-3.2	-1.5	-1.5	-2.9	-1.8	-1.9	NA	-2.3
B	Mill 2-2 Suction	"H_2O	-1.6	-1.7	-1.4	-1.8	NA	-1.8	-2.4	-2.3
B	Mill 2-3 Suction	"H_2O	-1.5	-2.7	-1.4	-1.7	-1.8	-1.6	-2.4	NA
B	Mill 2-4 Suction	"H_2O	-1.4	-1.4	-1.4	-1.8	-2.0	NA	-2.4	-2.4
B	Mill 2-5 Suction	"H_2O	-1.6	-1.6	NA	-1.9	-1.7	-1.6	-2.3	-2.4
B	Mill 2-1 Coal Flow	10^3LB/HR	0	85	86	0	71	72	0	55
B	Mill 2-2 Coal Flow	10^3LB/HR	80	81	84	68	0	70	51	50
B	Mill 2-3 Coal Flow	10^3LB/HR	79	0	82	62	68	69	50	0
B	Mill 2-4 Coal Flow	10^3LB/HR	79	79	82	61	66	0	50	48
B	Mill 2-5 Coal Flow	10^3LB/HR	80	80	0	62	67	70	51	50
B	Mill 2-1 Feeder Speed (1)	%	26	95	96	24	82	83	NA	64
B	Mill 2-2 Feeder Speed	%	95	96	96	82	NA	83	62	60
B	Mill 2-3 Feeder Speed	%	94	NA	94	80	80	82	60	NA
B	Mill 2-4 Feeder Speed	%	94	95	95	80	80	NA	60	58
B	Mill 2-5 Feeder Speed	%	94	94	NA	80	80	84	60	60
	BURNER TILT	± Degrees								
B	Position LF		+6	-3	-8	+17	-10	-10	+6	-8
B	Position LR		+8	-1	-4	+17	-7	-6	+6	-5
B	Position RF		+6	-4	-7	+13	-9	-11	+5	-8
B	Position RR		+6	-3	-6	+18	-9	-9	+6	-8
	MISCELLANEOUS									
B	Drum Level, In. ± Norm. H_2O Level		-1	-1	0.0	-0.5	-1	-1	-1	0
C	FD Fan 2-1	AMPS	209	209	208	342	NA	NA	NA	NA
C	FD Fan 2-2	AMPS	230	231	228	349	NA	NA	NA	NA
C	ID Fan 2-1	AMPS	380	380	385	342	345	350	312	171
C	ID Fan 2-2	AMPS	388	389	393	348	348	352	312	181
B	Flue Gas SO_2 in Stack	PPM	NA	NA	NA	NA	NA	NA	NA	28
B	Flue Gas NO_x in Stack	PPM	NA	NA	NA	NA	400	NA	400	380
C	Flue Gas Combustibles L	%	0.06	0.05	0.06	0.17	0.07	0.09	0.1	0.08
C	Flue Gas Combustibles R	%	0	0	0	0	0	0	0	0
C	Flue Gas O_2 L	%	3.33	2.85	2.16	2.27	3.11	2.85	3.97	3.08
C	Flue Gas O_2 R	%	2.49	3.41	4.00	2.70	2.58	2.89	3.02	3.85
C	Flue Gas O_2 Avg.	%	2.91	3.3	3.08	2.48	2.85	2.87	3.50	3.47
B	Ambient Temp.	°F	72	65	71	31	62	54	53	56
B	Ambient Rel. Humidity	%	24	28	21	82	20	45	47	37
B	Barometric Pressure	"Hg	23.76	23.81	24.20	23.30	23.65	23.58	23.66	23.96

C = Computer Data; B = Board Data
(1) Feeder Speed in % of Control Signal

BIASED FIRING OPERATION STUDY

BOARD & COMPUTER DATA

	TEST NO.		9	10	11	12	13	14	15	16
	DATE	1975	9/19	9/18	9/18	10/11	12/13	12/13	7/23	7/24
	TIME		14:35	09:45	14:10	14:45	12:00	10:15	10:40	09:55
C	LOAD	MW	427	429	430	351	356	357	256	259
	MILL DATA									
C	MILL 2-1	AMPS	NA	NA	NA	NA	94.8	95.6	79.6	81.0
C	MILL 2-2	AMPS	NA	NA	NA	NA	91.4	91.8	NA	76.4
C	MILL 2-3	AMPS	NA	NA	NA	NA	64.7	86.5	77.6	80.0
C	MILL 2-4	AMPS	NA	NA	NA	NA	86.7	86.8	79.8	NA
C	MILL 2-5	AMPS	NA	NA	NA	NA	85.5	61.9	85.3	84.5
C	COAL AIR TEMP. MILL 2-1	°F	117	148	149	156	150	150	148	147
C	COAL AIR TEMP. MILL 2-2	°F	148	148	148	149	160	149	NA	NA
C	COAL AIR TEMP. MILL 2-3	°F	146	147	147	149	148	148	148	148
C	COAL AIR TEMP. MILL 2-4	°F	147	147	147	147	147	148	146	88
C	COAL AIR TEMP. MILL 2-5	°F	148	147	149	150	150	147	148	149
B	MILL 2-1 EXH. DISCHARGE	"H_2O	5.5	8.1	8.5	NA	8.0	8.1	5.5	5.5
B	MILL 2-2 EXH. DISCHARGE	"H_2O	7.5	5.5	7.5	5.8	7.5	7.5	NA	6.1
B	MILL 2-3 EXH. DISCHARGE	"H_2O	8.2	8.4	8.2	7.3	5.0	7.1	7.2	7.6
B	MILL 2-4 EXH. DISCHARGE	"H_2O	10.0	10.3	8.0	7.4	7.2	7.5	6.5	NA
B	MILL 2-5 EXH. DISCHARGE	"H_2O	8.5	8.6	8.5	7.3	7.3	4.1	7.0	7.1
B	MILL 2-1 SUCTION	"H_2O	-3.1	-1.5	-1.6	NA	-1.7	-1.6	-2.3	-2.2
B	MILL 2-2 SUCTION	"H_2O	-1.6	-3.0	-1.7	-3.2	-1.8	-1.8	NA	-2.6
B	MILL 2-3 SUCTION	"H_2O	-1.4	-1.4	-1.5	-1.5	-2.8	-1.7	-2.3	-2.2
B	MILL 2-4 SUCTION	"H_2O	-1.4	-1.4	-3.0	-1.7	-1.8	-1.8	-2.5	NA
B	MILL 2-5 SUCTION	"H_2O	-1.5	-1.6	-1.6	-1.5	-1.9	-2.9	-2.3	-2.3
B	MILL 2-1 COAL FLOW	10^3 LB/HR	0	79	84	0	75	75	43	48
B	MILL 2-2 COAL FLOW	10^3 LB/HR	84	0	80	76	64	65	0	35
B	MILL 2-3 COAL FLOW	10^3 LB/HR	83	79	79	76	0	58	40	45
B	MILL 2-4 COAL FLOW	10^3 LB/HR	82	78	0	74	58	59	47	0
B	MILL 2-5 COAL FLOW	10^3 LB/HR	81	79	80	75	59	0	56	55
B	MILL 2-1 FEEDER SPEED (1)	%	26	90	94	NA	79	78	49	56
B	MILL 2-2 FEEDER SPEED	%	100	NA	94	91	79	78	NA	42
B	MILL 2-3 FEEDER SPEED	%	99	94	94	90	NA	76	49	55
B	MILL 2-4 FEEDER SPEED	%	96	94	NA	91	76	76	58	NA
B	MILL 2-5 FEEDER SPEED	%	90	94	94	89	78	NA	66	67
	BURNER TILT	± DEGREES								
B	POSITION LF		+16	+9	+2	+5	+7	-8	+11	+10
B	POSITION LR		+17	+10	+4	+6	+10	-6	+12	+12
B	POSITION RF		+15	+9	+2	+5	+7	-9	+13	+13
B	POSITION RR		+18	+9	+2	+6	+9	-8	+13	+11
	MISCELLANEOUS									
B	DRUM LEVEL, IN. ± NORM. H_2O LEVEL		-1	-1.1	-1	-1	-0.5	-0.5	-1	-0.5
C	FD FAN 2-1	AMPS	NA	NA	NA	NA	358	358	171	171
C	FD FAN 2-2	AMPS	NA	NA	NA	NA	364	366	171	170
C	ID FAN 2-1	AMPS	212	216	215	348	358	357	311	312
C	ID FAN 2-2	AMPS	236	241	239	352	364	366	310	310
B	FLUE GAS SO_2 IN STACK	PPM	NA	NA	NA	NA	NA	NA	NA	NA
B	FLUE GAS NO_x IN STACK	PPM	NA	NA	NA	396	NA	NA	NA	NA
C	FLUE GAS COMBUSTIBLES L	%	0.08	0.11	0.07	0.05	0.16	0.16	0.1	0.09
C	FLUE GAS COMBUSTIBLES R	%	0	0	0	0	0	0	0	0
C	FLUE GAS O_2 L	%	4.09	4.74	4.09	3.77	3.52	3.06	3.54	3.28
C	FLUE GAS O_2 R	%	3.76	3.83	4.01	3.87	4.6	5.16	4.10	3.90
C	FLUE GAS O_2 AVG.	%	3.92	4.29	4.05	3.82	4.06	4.11	3.85	3.59
B	AMBIENT TEMP.	°F	79	67	74	68	31	30	87	79
B	AMBIENT REL. HUMIDITY	%	27	38	27	20	81	85	28	36
B	BAROMETRIC PRESSURE	"Hg	23.80	23.83	23.83	23.66	23.33	23.38	24.00	24.05

C = COMPUTER DATA; B = BOARD DATA
(1) FEEDER SPEED IN % OF CONTROL SIGNAL

OVERFIRE AIR OPERATION STUDY

BOARD AND COMPUTER DATA

TEST NO.		1	2	3	4	5	6	7	8
Date	1975	9/17	9/26	9/26	9/26	9/26	10/1	10/1	10/1
Time		10:20	09:40	11:30	15:30	17:15	18:00	19:30	21:00
C Load	MW	428	430	430	430	431	430	428	428
FLOWS	10^3LB/HR								
C Feedwater		2876	2893	2900	2895	2901	2893	2910	2903
B Main Steam		3000	3040	3038	3025	3050	3038	3040	3040
C Superheat Spray L		0	0	0	0	0	0	0	0
C Superheat Spray R		0	0	0	0	0	0	0	0
C Reheat Spray		9.1	7.8	7.2	28.2	22.4	0	0	0
C Ext. Stm. to Stm. AH 2-1		12.2	58.9	58.8	58.8	58.8	58.8	58.8	58.8
C Ext. Stm. to Stm. AH 2-2		12.2	58.9	58.8	58.8	58.8	58.8	58.8	58.8
C Aux. Stm. to Stm. AH 2-1		0	0	0	0	0	0	0	0
C Aux. Stm. to Stm. AH 2-2		0	0	0	0	0	0	0	0
C Aux. Stm. to SJAE		3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
B Air Flow to Boiler		3460	3380	3380	3380	3380	3060	3130	3150
PRESSURES STEAM & WATER	PSIG								
C Feedwater to Econ.		2806	2815	2820	2816	2821	2814	2815	2811
C Boiler Drum		2716	2720	2721	2720	2725	2717	2716	2715
C Turbine Throttle		2409	2422	2420	2420	2427	2418	2416	2413
C Turbine 1st Stage		1826	1828	1828	1828	1833	1826	1825	1824
C RH Inlet Left		572	573	573	575	577	572	571	571
C RH Inlet Right		575	578	578	579	581	575	575	575
C RH Inlet Avg.		574	575	575	577	579	574	573	573
C RH Outlet		531	535	534	536	538	532	533	532
C HP Htr. 2-7 Stm. In		360	359	360	360	359	360	359	362
PRESSURES AIR & GAS	"H_2O								
B FD Fan Discharge R		10.3	9.5	9.5	10.0	10.0	9.5	9.2	8.8
B FD Fan Discharge L		10.3	9.5	9.5	10.0	10.0	9.5	9.2	8.8
B FD Fan Discharge Avg.		10.3	9.5	9.5	10.0	10.0	9.5	9.2	8.8
C AH 2-1 Air Diff. Press. R		3.80	3.73	3.70	3.70	3.70	3.25	3.28	3.30
C AH 2-2 Air Diff. Press. L		4.34	4.21	4.19	4.21	4.22	3.65	3.70	3.72
C AH Air Diff. Press. Avg.		4.07	3.97	3.94	3.96	3.96	3.45	3.49	3.51
B Windbox Press. R		4.0	3.5	3.4	3.3	3.3	4.5	3.7	3.2
B Windbox Press. L		4.0	3.5	3.4	3.3	3.3	4.5	3.7	3.2
B Windbox Press. Avg.		4.0	3.5	3.4	3.3	3.3	4.5	3.7	3.2
B Furnace Draft		-0.68	-1.0	-1.1	-1.0	-1.1	-1.0	-1.0	-1.0
C SH Draft Diff.		1.95	2.19	2.01	1.91	2.13	1.81	1.91	1.95
C Econ. Draft Diff.		2.66	2.53	2.69	2.75	2.81	2.24	2.49	2.44
B AH 2-1 Gas Out. Press. R		-14.5	-15.0	-15.0	-15.0	-15.0	-12.5	-12.8	-12.9
B AH 2-2 Gas Out. Press. L		-12.8	-13.0	-12.9	-13.0	-12.8	-13.5	-13.8	-13.7
B AH Gas Out. Press. Avg.		-13.6	-14.0	-14.0	-14.0	-13.9	-13.0	-13.3	-13.3
B ID Fan 2-1 Inlet Press. R		-17.3	-18.5	-19.0	-18.5	-18.5	-15.0	-15.0	-15.0
B ID Fan 2-2 Inlet Press. L		-14.0	-14.0	-14.0	-14.0	-14.0	-15.0	-15.1	-15.1
B ID Fan Inlet Press. Avg.		-15.6	-16.2	-16.5	-16.2	-16.2	-15.0	-15.0	-15.0

B = Board Data
C = Computer Data

OVERFIRE AIR OPERATION STUDY

BOARD AND COMPUTER DATA

TEST NO.		9	10	11	12	13	14	15	16
Date	1975	9/27	9/27	9/27	10/5	10/4	10/5	10/4	10/3
Time		13:30	12:00	14:00	13:45	16:00	12:00	14:15	18:30
C Load	MW	428	429	429	427	434	422	429	427
FLOWS	10^3LB/HR								
C Feedwater		2885	2881	2891	2909	2853	2889	2882	2904
B Main Steam		3033	3050	3050	3000	3000	3000	3000	3050
C Superheat Spray L		0	0	0	0	0	0	0	0
C Superheat Spray R		0	0	0	0	0	0	0	0
C Reheat Spray		0	0	0	0	17.3	0	0	7.9
C Ext. Stm. to Stm. AH 2-1		58.8	58.9	58.8	58.8	58.8	58.8	58.8	58.8
C Ext. Stm. to Stm. AH 2-2		58.8	58.9	58.8	58.8	58.8	58.8	58.8	58.8
C Aux. Stm. to Stm. AH 2-1		0	0	0	0	0	0	0	0
C Aux. Stm. to Stm. AH 2-2		0	0	0	0	0	0	0	0
C Aux. Stm. to SJAE		3.0	3.1	3.0	3.0	3.0	3.0	3.0	3.0
B Air Flow to Boiler		3770	3710	3730	3130	3250	3140	3200	3190
PRESSURES STEAM & WATER	PSIG								
C Feedwater to Econ.		2810	2818	2818	2813	2814	2807	2812	2808
C Boiler Drum		2703	2716	2719	2719	2718	2705	2713	2713
C Turbine Throttle		2423	2417	2420	2415	2420	2411	2417	2415
C Turbine 1st Stage		1812	1827	1828	1829	1829	1806	1823	1824
C RH Inlet Left		567	569	570	573	576	565	572	573
C RH Inlet Right		571	573	573	577	579	569	575	577
C RH Inlet Avg.		569	571	572	575	578	567	574	575
C RH Outlet		531	530	531	533	536	528	533	534
C HP Htr. 2-7 Stm. In		366	362	359	360	359	362	361	360
PRESSURES AIR & GAS	"H_2O								
B FD Fan Discharge R		11.0	11.8	11.8	9.3	9.8	9.2	9.1	9.5
B FD Fan Discharge L		11.0	11.8	11.8	9.3	9.8	9.2	9.1	9.5
B FD Fan Discharge Avg.		11.0	11.8	11.8	9.3	9.8	9.2	9.1	9.5
C AH 2-1 Air Diff. Press. R		4.42	4.41	4.40	3.37	3.56	3.33	3.42	3.44
C AH 2-2 Air Diff. Press. L		5.02	4.84	4.84	3.81	3.98	3.73	3.90	3.90
C AH Air Diff. Press. Avg.		4.72	4.62	4.62	3.59	3.77	3.53	3.66	3.67
B Windbox Press. R		3.5	4.3	4.5	3.5	3.8	3.4	3.5	3.5
B Windbox Press. L		3.5	4.3	4.5	3.5	3.8	3.4	3.5	3.5
B Windbox Press. Avg.		3.5	4.3	4.5	3.5	3.8	3.4	3.5	3.5
B Furnace Draft		-1.0	-1.0	-1.0	-1.0	-1.2	-1.0	-1.0	-1.0
C SH Draft Diff.		2.54	2.26	2.36	1.82	1.95	1.73	1.84	1.80
C Econ. Draft Diff.		3.16	3.08	3.11	2.44	2.51	2.31	2.41	2.39
B AH 2-1 Gas Out. Press. R		-15.0	-15.0	-15.0	-13.5	-14.3	-13.5	-13.6	-13.5
B AH 2-2 Gas Out. Press. L		-15.0	-15.0	-15.0	-13.5	-14.3	-13.4	-13.6	-13.4
B AH Gas Out. Press. Avg.		-15.0	-15.0	-15.0	-13.5	-14.3	-13.4	-13.6	-13.4
B ID Fan 2-1 Inlet Press. R		-21.5	-19.1	-19.0	-15.8	-16.9	-15.6	-16.0	-16.0
B ID Fan 2-2 Inlet Press. L		-17.5	-19.1	-19.0	-14.8	-15.4	-14.5	-14.8	-14.5
B ID Fan Inlet Press. Avg.		-19.5	-19.1	-19.0	-15.3	-16.2	-15.0	-15.4	-15.2

B = Board Data
C = Computer Data

OVERFIRE AIR OPERATION STUDY

BOARD AND COMPUTER DATA

TEST NO.		17	18	19	20	21	22	23	24
Date	1975	10/3	10/3	10/6	10/8	10/10	10/9	10/12	10/5
Time		22:30	20:30	19:00	10:30	01:45	01:15	08:15	18:45
C Load	MW	423	430	417	426	356	358	253	266
FLOWS	10^3LB/HR								
C Feedwater		2926	2885	2900	2908	2333	2307	1665	1657
B Main Steam		3100	3038	3050	3050	2400	2400	1650	1650
C Superheat Spray L		0	0	0	0	0	0	0	0
C Superheat Spray R		0	0	0	0	0	0	0	0
C Reheat Spray		22.9	18.7	0	0	0	4.5	0	0
C Ext. Stm. to Stm. AH 2-1		58.8	58.8	58.8	58.8	58.8	58.8	28.2	58.8
C Ext. Stm. to Stm. AH 2-2		58.8	58.8	58.8	58.8	58.8	58.8	28.5	58.8
C Aux. Stm. to Stm. AH 2-1		0	0	0	0	0	0	0	0
C Aux. Stm. to Stm. AH 2-2		0	0	0	0	0	0	0	0
C Aux. Stm. to SJAE		3.0	3.0	3.0	3.2	3.0	3.1	3.0	3.0
B Air Flow to Boiler		3180	3240	3100	3110	2460	2640	1800	1810
PRESSURES STEAM & WATER	PSIG								
C Feedwater to Econ.		2813	2806	2813	2816	2705	2701	2592	2593
C Boiler Drum		2715	2711	2715	2720	2628	2631	2537	2532
C Turbine Throttle		2418	2413	2415	2419	2416	2420	2416	2414
C Turbine 1st Stage		1826	1824	1824	1829	1442	1438	NA	1008
C RH Inlet Left		574	574	572	571	464	465	NA	334
C RH Inlet Right		578	579	576	575	468	469	NA	336
C RH Inlet Avg.		576	576	574	573	460	457	NA	335
C RH Outlet		535	535	524	532	428	429	293	301
C HP Htr. 2-7 Stm. In		357	360	359	363	380	384	404	408
PRESSURES AIR & GAS	"H_2O								
B FD Fan Discharge R		9.0	9.4	8.8	8.5	4.8	6.8	2.5	2.5
B FD Fan Discharge L		8.9	9.4	8.8	8.5	4.6	6.6	2.5	2.5
B FD Fan Discharge Avg.		9.0	9.4	8.8	8.5	4.7	6.7	2.5	2.5
C AH 2-1 Air Diff. Press. R		3.35	3.44	3.23	3.30	2.21	2.50	1.36	1.38
C AH 2-2 Air Diff. Press. L		3.79	3.88	3.64	3.72	2.58	2.87	1.52	1.57
C AH Air Diff. Press. Avg.		3.57	3.66	3.44	3.51	2.40	2.68	1.44	1.48
B Windbox Press. R		3.1	3.5	3.3	3.0	1.0	2.5	0	0
B Windbox Press. L		3.1	3.5	3.3	3.0	1.0	2.5	0	0
B Windbox Press. Avg.		3.1	3.5	3.3	3.0	1.0	2.5	0	0
B Furnace Draft		-1.2	-1.2	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
C SH Draft Diff.		1.93	2.00	1.85	1.77	1.13	1.33	0.53	0.60
C Econ. Draft Diff.		2.45	2.61	2.43	2.45	1.71	1.80	0.98	0.88
B AH 2-1 Gas Out. Press. R		-13.5	-13.8	-13.3	-13.8	-10.6	-10.0	-6.8	-6.8
B AH 2-2 Gas Out. Press. L		-13.5	-13.8	-12.8	-13.2	-9.8	-10.0	-6.0	-6.6
B AH Gas Out. Press. Avg.		-13.5	-13.8	-13.0	-13.5	-10.2	-10.0	-6.4	-6.7
B ID Fan 2-1 Inlet Press. R		-15.8	-16.0	-15.5	-15.5	-11.6	-11.8	-7.5	-8.0
B ID Fan 2-2 Inlet Press. L		-14.8	-15.0	-14.0	-14.0	-10.6	-10.5	-6.8	-7.6
B ID Fan Inlet Press. Avg.		-15.3	-15.5	-14.8	-14.8	-11.1	-11.2	-7.2	-7.8

B = Board Data
C = Computer Data

OVERFIRE AIR OPERATION STUDY

BOARD AND COMPUTER DATA

TEST NO.		1	2	3	4	5	6	7	8
Date	1975	9/17	9/26	9/26	9/26	9/26	10/1	10/1	10/1
Time		10:20	09:40	11:30	15:30	17:15	18:00	19:30	21:00
C Load	MW	428	430	430	430	431	430	428	428
TEMPERATURES AIR & GAS	°F								
C AH 2-1 Air In Temp.		103	108	108	109	109	96	96	95
C AH 2-2 Air In Temp.		98	94	94	91	91	110	109	109
C AH Air In Temp. Avg.		100	101	101	100	100	103	102	102
C AH 2-1 Air Out Temp.		521	513	513	511	512	534	532	533
C AH 2-2 Air Out Temp.		544	546	548	545	547	534	535	536
C AH Air Out Temp. Avg.		532	530	530	528	530	534	534	534
C AH 2-1 Gas In Temp.		722	714	715	710	711	716	714	713
C AH 2-2 Gas In Temp.		722	701	703	703	708	707	707	709
C AH Gas In Temp. Avg.		722	708	709	706	710	712	710	711
C AH 2-1 Gas Out Temp.		268	261	261	261	261	282	280	279
C AH 2-2 Gas Out Temp.*		279	286	287	286	288	264	265	265
C AH Gas Out Temp. Avg.		274	274	274	274	274	273	272	272
TEMPERATURES STEAM & WATER	°F								
C FW In Temp. to Econ.		484	485	485	486	486	485	484	485
C Econ. Out. Avg.		576	577	577	574	575	570	570	571
C Boiler Downcomer		678	678	678	678	679	678	678	678
C SH DESH Inlet L		752	749	751	749	750	745	747	749
C SH DESH Inlet R		759	763	759	757	756	755	756	760
C SH DESH Inlet Avg.		756	756	755	753	753	750	752	754
C SH DESH Outlet L		758	754	756	755	757	751	753	755
C SH DESH Outlet R		764	764	763	759	759	760	758	761
C SH DESH Outlet Avg.		761	759	760	757	758	756	756	758
C SH Outlet		987	983	983	989	987	991	980	982
C Throttle Steam		976	971	973	979	974	980	971	974
C RH Turbine L		616	613	613	619	616	619	612	615
C RH Turbine R		617	613	614	620	616	619	613	615
C RH Turbine Avg.		616	613	614	619	616	619	612	615
C RH Boiler L		601	598	600	576	581	615	608	611
C RH Boiler R		595	[illegible]	595	562	569	614	608	610
C RH Boiler Avg.		598	[illegible]	598	569	575	614	608	610
C RH Outlet		995	1004	1002	994	1002	1020	1011	1014
C HP Htr. 2-7 Stm. In		615	611	612	619	614	618	612	613
C HP Htr. 2-7 FW In		415	415	415	416	416	415	415	416
C HP Htr. 2-7 Drain		423	423	423	424	424	424	424	424
C Aux. Steam Temp.		528	528	529	530	530	531	530	531
FAN DAMPER POSITION	% Open								
B FD Fans		75	73	74	74	74	70	70	70
B ID Fans		67	66	65	66	66	60	63	62
SPRAY VALVE POSITION	% Open								
B SH Spray		0	0	0	0	0	0	0	0
B RH Spray		15	14	13	28	25	0	0	0

B = Board Data
C = Computer Data
* TC Reading Open

OVERFIRE AIR OPERATION STUDY

BOARD AND COMPUTER DATA

TEST NO.		9	10	11	12	13	14	15	16
Date	1975	9/27	9/27	9/27	10/5	10/4	10/5	10/4	10/3
Time		13:30	12:00	14:00	13:45	16:00	12:00	14:15	18:30
C Load	MW	428	429	429	427	434	422	429	427
TEMPERATURES AIR & GAS	°F								
C AH 2-1 Air In Temp.		106	96	96	101	100	101	100	99
C AH 2-2 Air In Temp.		98	104	105	103	103	104	104	104
C AH Air In Temp. Avg.		102	100	100	102	102	102	102	102
C AH 2-1 Air Out Temp.		512	530	531	527	531	524	526	526
C AH 2-2 Air Out Temp.		543	545	545	540	541	536	538	535
C AH Air Out Temp. Avg.		528	538	538	534	536	530	532	530
C AH 2-1 Gas In Temp.		724	728	729	715	724	710	714	711
C AH 2-2 Gas In Temp.		713	733	731	714	716	709	709	714
C AH Gas In Temp. Avg.		718	730	730	714	720	710	712	712
C AH 2-1 Gas Out Temp.		266	281	282	276	277	274	275	275
C AH 2-2 Gas Out Temp.*		282	270	271	274	273	273	272	270
C AH Gas Out Temp. Avg.		274	276	276	275	275	274	274	272
TEMPERATURES STEAM & WATER	°F								
C FW In Temp. to Econ.		485	484	484	484	486	484	485	485
C Econ. Out. Avg.		584	586	587	571	574	568	571	570
C Boiler Downcomer		678	678	678	678	678	677	678	678
C SH DESH Inlet L		751	758	759	748	748	742	744	740
C SH DESH Inlet R		758	762	762	748	761	742	751	751
C SH DESH Inlet Avg.		754	760	760	748	754	742	748	746
C SH DESH Outlet L		757	765	766	753	754	748	750	747
C SH DESH Outlet R		761	769	770	753	765	749	756	757
C SH DESH Outlet Avg.		759	767	768	753	760	748	753	752
C SH Outlet		983	994	993	977	1006	969	988	978
C Throttle Steam		973	980	982	967	997	960	977	968
C RH Turbine L		613	620	621	609	634	602	617	611
C RH Turbine R		614	620	621	609	635	603	618	611
C RH Turbine Avg.		614	620	621	609	634	602	618	611
C RH Boiler L		609	616	618	605	612	600	611	596
C RH Boiler R		609	616	616	604	603	599	610	588
C RH Boiler Avg.		609	616	617	604	608	600	610	592
C RH Outlet		1012	1012	1011	1006	1026	991	1017	995
C HP Htr. 2-7 Stm. In		613	621	620	608	635	602	616	609
C HP Htr. 2-7 FW In		413	415	415	415	416	414	415	415
C HP Htr. 2-7 Drain		423	423	423	424	424	423	424	423
C Aux. Steam Temp.		525	542	545	525	577	518	530	526
FAN DAMPER POSITION	% Open								
B FD Fans		80	79	80	72	73	71	72	72
B ID Fans		74	71	71	63	65	62	64	64
SPRAY VALVE POSITION	% Open								
B SH Spray		0	0	0	0	0	0	0	0
B RH Spray		0	0	0	0	23	0	3	15

B = Board Data
C = Computer Data
* TC Reading Open

OVERFIRE AIR OPERATION STUDY

BOARD AND COMPUTER DATA

TEST NO.		17	18	19	20	21	22	23	24
Date	1975	10/3	10/3	10/6	10/8	10/10	10/9	10/12	10/5
Time		22:30	20:30	19:00	10:30	01:45	01:15	08:15	18:45
C Load	MW	423	430	417	426	356	358	253	266
TEMPERATURES AIR & GAS	°F								
C AH 2-1 Air In Temp.		98	97	102	97	109	110	116	115
C AH 2-2 Air In Temp.		104	103	104	103	108	112	118	117
C AH Air In Temp. Avg.		101	100	103	100	108	111	117	116
C AH 2-1 Air Out Temp.		524	527	524	522	504	505	468	476
C AH 2-2 Air Out Temp.		534	538	534	532	511	510	470	476
C AH Air Out Temp. Avg.		529	532	529	527	508	508	469	476
C AH 2-1 Gas In Temp.		708	715	710	710	659	672	592	608
C AH 2-2 Gas In Temp.		708	721	702	702	655	673	591	607
C AH Gas In Temp. Avg.		708	718	706	706	657	672	592	608
C AH 2-1 Gas Out Temp.		274	275	273	272	262	262	248	252
C AH 2-2 Gas Out Temp.*		271	272	272	271	266	259	250	254
C AH Gas Out Temp. Avg.		272	274	272	272	264	260	249	253
TEMPERATURES STEAM & WATER	°F								
C FW In Temp. to Econ.		484	486	484	484	464	464	430	434
C Econ. Out. Avg.		569	573	567	568	539	545	498	504
C Boiler Downcomer		678	678	678	678	672	673	668	668
C SH DESH Inlet L		739	747	744	739	738	751	730	740
C SH DESH Inlet R		752	759	742	743	742	757	733	741
C SH DESH Inlet Avg.		746	753	743	741	740	754	732	740
C SH DESH Outlet L		746	753	744	744	743	758	734	741
C SH DESH Outlet R		750	758	747	748	744	756	737	746
C SH DESH Outlet Avg.		748	756	746	746	744	757	736	744
C SH Outlet		961	989	961	972	983	995	973	1005
C Throttle Steam		951	981	958	960	976	989	963	996
C RH Turbine L		597	622	602	603	579	591	NA	550
C RH Turbine R		597	623	603	603	585	596	NA	562
C RH Turbine Avg.		597	622	602	603	582	594	NA	556
C RH Boiler L		555	595	599	601	577	576	519	547
C RH Boiler R		544	581	599	599	579	573	529	557
C RH Boiler Avg.		550	588	599	600	578	574	524	552
C RH Outlet		965	1007	987	991	983	1002	954	988
C HP Htr. 2-7 Stm. In		594	620	603	602	580	591	529	556
C HP Htr. 2-7 FW In		415	416	415	415	399	400	371	374
C HP Htr. 2-7 Drain		423	424	424	423	405	405	375	377
C Aux. Steam Temp.		511	533	518	513	530	552	519	535
FAN DAMPER POSITION	% Open								
B FD Fans		70	70	70	68	57	61	46	46
B ID Fans		63	62	60	60	53	55	41	41
SPRAY VALVE POSITION	% Open								
B SH Spray		0	0	0	0	0	0	0	7
B RH Spray		25	22	0	0	0	12	0	0

B = Board Data
C = Computer Data
* TC Reading Open

OVERFIRE AIR OPERATION STUDY

BOARD AND COMPUTER DATA

TEST NO.		1	2	3	4	5	6	7	8
Date	1975	9/17	9/26	9/26	9/26	9/26	10/1	10/1	10/1
Time		10:20	09:40	11:30	15:30	17:15	18:00	19:30	21:00
C Load	MW	428	430	430	430	431	430	428	428
MILL DATA									
C Mill 2-1	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C Mill 2-2	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C Mill 2-3	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C Mill 2-4	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C Mill 2-5	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C Coal Air Temp. Mill 2-1	°F	148	149	148	149	149	150	150	149
C Coal Air Temp. Mill 2-2	°F	148	150	150	150	150	150	150	149
C Coal Air Temp. Mill 2-3	°F	147	148	147	147	147	149	149	147
C Coal Air Temp. Mill 2-4	°F	146	148	148	148	148	146	146	146
C Coal Air Temp. Mill 2-5	°F	148	149	149	149	149	148	148	149
B Mill 2-1 Exh. Disch.	"H_2O	7.0	6.0	6.2	6.0	6.0	7.4	7.1	7.3
B Mill 2-2 Exh. Disch.	"H_2O	7.0	6.4	6.5	6.5	6.5	6.8	7.1	6.7
B Mill 2-3 Exh. Disch.	"H_2O	8.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
B Mill 2-4 Exh. Disch.	"H_2O	9.0	8.7	8.8	8.8	8.5	7.0	7.0	7.0
B Mill 2-5 Exh. Disch.	"H_2O	8.0	7.2	7.3	7.9	7.5	7.4	7.0	7.4
B Mill 2-1 Suction	"H_2O	-1.8	-1.7	-1.8	-1.8	-1.8	-2.0	-2.0	-2.0
B Mill 2-2 Suction	"H_2O	-2.0	-1.9	-1.9	-2.0	-2.0	-2.0	-2.0	-1.9
B Mill 2-3 Suction	"H_2O	-1.8	-1.8	-1.9	-1.9	-1.9	-1.8	-1.9	-1.9
B Mill 2-4 Suction	"H_2O	-1.7	-1.7	-1.7	-1.8	-1.7	-2.0	-2.1	-2.1
B Mill 2-5 Suction	"H_2O	-2.0	-2.0	-2.1	-2.0	-2.0	-1.8	-1.9	-2.0
B Mill 2-1 Coal Flow	10^3LB/HR	66	67	68	69	68	69	67	69
B Mill 2-2 Coal Flow	10^3LB/HR	64	65	66	66	66	66	64	66
B Mill 2-3 Coal Flow	10^3LB/HR	63	63	63	64	64	65	63	65
B Mill 2-4 Coal Flow	10^3LB/HR	63	64	63	64	64	64	63	64
B Mill 2-5 Coal Flow	10^3LB/HR	63	65	64	64	65	66	64	66
B Mill 2-1 Feeder Speed *	%	75	76	78	79	78	79	77	79
B Mill 2-2 Feeder Speed	%	76	76	77	78	77	79	76	79
B Mill 2-3 Feeder Speed	%	75	75	75	76	76	78	76	77
B Mill 2-4 Feeder Speed	%	75	77	77	77	78	78	76	78
B Mill 2-5 Feeder Speed	%	75	77	76	77	77	78	77	78
BURNER TILT	± Degrees								
B Position LF		+6	-11	-11	-14	-14	+9	+9	+10
B Position LR		+7	-9	-9	-12	-10	+10	+10	+10
B Position RF		+5	-10	-12	-14	-15	+7	+8	+8
B Position RR		+6	-10	-10	-14	-13	+9	+10	+11
MISCELLANEOUS									
B Drum Level "± Norm. H_2O Level		-1	0	0	0	0	0	0	0
C FD Fan 2-1	AMPS	216	215	214	214	214	208	208	207
C FD Fan 2-2	AMPS	240	235	235	235	235	229	228	226
C ID Fan 2-1	AMPS	397	389	385	385	385	400	404	400
C ID Fan 2-2	AMPS	405	424	419	419	416	373	376	374
B Flue Gas SO_2 in Stack	PPM	NA	NA	NA	NA	NA	60	60	70
B Flue Gas NO_x in Stack	PPM	NA	627	NA	515	580	400	408	400
C Flue Gas Combustibles L	%	0.11	0.11	0.10	0.06	0.06	0.06	0.08	0.08
C Flue Gas Combustibles R	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C Flue Gas O_2 L	%	4.13	4.52	4.16	4.05	3.71	2.96	2.31	2.24
C Flue Gas O_2 R	%	4.06	3.62	3.86	3.77	4.19	2.54	2.49	3.64
C Flue Gas O_2 Avg.	%	4.10	4.07	4.01	3.91	3.95	2.75	2.40	2.94
B Ambient Temp.	°F	73	67	74	74	70	64	57	54
B Ambient Rel. Humidity	%	43	29	25	20	24	28	33	35
B Barometric Press.	"Hg	23.86	23.97	23.96	23.93	23.92	24.05	24.05	24.07

B = Board Data
C = Computer Data
* Feeder Speed in % of Control Signal

OVERFIRE AIR OPERATION STUDY

BOARD AND COMPUTER DATA

TEST NO.		9	10	11	12	13	14	15	16
DATE	1975	9/27	9/27	9/27	10/5	10/4	10/5	10/4	10/3
TIME		13:30	12:00	14:00	13:45	16:00	12:00	14:15	18:30
C LOAD	MW	428	429	429	427	434	422	429	427
MILL DATA									
C MILL 2-1	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C MILL 2-2	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C MILL 2-3	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C MILL 2-4	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C MILL 2-5	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C COAL AIR TEMP. MILL 2-1	°F	148	149	149	148	150	148	150	148
C COAL AIR TEMP. MILL 2-2	°F	149	149	150	148	149	148	150	150
C COAL AIR TEMP. MILL 2-3	°F	147	147	148	147	146	147	146	147
C COAL AIR TEMP. MILL 2-4	°F	141	146	146	145	145	145	145	145
C COAL AIR TEMP. MILL 2-5	°F	148	148	149	149	149	148	149	149
B MILL 2-1 EXH. DISCH.	"H_2O	5.8	7.2	7.2	8.0	6.6	8.0	6.9	7.5
B MILL 2-2 EXH. DISCH.	"H_2O	7.0	6.9	6.8	6.7	6.8	7.0	7.0	6.9
B MILL 2-3 EXH. DISCH.	"H_2O	7.0	7.0	7.0	7.3	7.3	7.0	7.1	7.4
B MILL 2-4 EXH. DISCH.	"H_2O	8.5	6.9	7.0	7.3	7.0	7.1	7.0	7.0
B MILL 2-5 EXH. DISCH.	"H_2O	7.5	7.2	7.5	7.0	7.1	7.3	7.4	7.1
B MILL 2-1 SUCTION	"H_2O	-1.9	-1.9	-1.9	-1.9	-2.1	-2.0	-2.1	-2.0
B MILL 2-2 SUCTION	"H_2O	-2.0	-1.8	-1.8	-2.0	-1.9	-2.0	-2.0	-1.9
B MILL 2-3 SUCTION	"H_2O	-1.8	-1.7	-1.8	-1.9	-1.8	-2.1	-1.9	-1.8
B MILL 2-4 SUCTION	"H_2O	-1.7	-2.0	-2.0	-2.2	-2.0	-2.2	-2.1	-2.1
B MILL 2-5 SUCTION	"H_2O	-2.0	-1.9	-1.9	-2.0	-2.0	-2.1	-2.0	-2.0
B MILL 2-1 COAL FLOW	10^3LB/HR	60	69	68	72	60	71	60	67
B MILL 2-2 COAL FLOW	10^3LB/HR	66	67	66	65	67	65	67	64
B MILL 2-3 COAL FLOW	10^3LB/HR	64	65	64	60	66	60	66	63
B MILL 2-4 COAL FLOW	10^3LB/HR	64	64	63	60	65	60	65	62
B MILL 2-5 COAL FLOW	10^3LB/HR	66	66	65	61	67	61	67	64
B MILL 2-1 FEEDER SPEED *	%	69	79	78	83	69	83	69	77
B MILL 2-2 FEEDER SPEED	%	79	79	78	78	79	77	80	76
B MILL 2-3 FEEDER SPEED	%	77	77	76	73	79	72	78	75
B MILL 2-4 FEEDER SPEED	%	78	77	78	74	79	71	78	77
B MILL 2-5 FEEDER SPEED	%	78	78	78	75	79	73	79	77
BURNER TILT	± DEGREES								
B POSITION LF		+10	+16	+12	-20	-1	-23	-1	+21
B POSITION LR		+10	+17	+12	-19	+1	-19	+1	+24
B POSITION RF		+9	+15	+11	-23	0	-23	0	+20
B POSITION RR		+11	+18	+13	-19	0	-20	0	+23
MISCELLANEOUS									
B DRUM LEVEL "± NORM. H_2O LEVEL		0	0	0	0	0	0	0	0
C FD FAN 2-1	AMPS	230	231	230	207	210	207	208	210
C FD FAN 2-2	AMPS	255	258	256	228	233	228	230	232
C ID FAN 2-1	AMPS	435	475	477	392	400	390	396	398
C ID FAN 2-2	AMPS	461	419	419	385	390	383	387	388
B FLUE GAS SO_2 IN STACK	PPM	107	50	50	30	40	10	40	63
B FLUE GAS NO_x IN STACK	PPM	400	408	400	370	360	360	358	373
C FLUE GAS COMBUSTIBLES L	%	0.07	0.11	0.06	0.06	0.07	0.11	0.09	0.08
C FLUE GAS COMBUSTIBLES R	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C FLUE GAS O_2 L	%	5.12	5.51	5.20	2.67	3.27	2.72	3.45	3.41
C FLUE GAS O_2 R	%	5.35	5.75	6.06	4.14	3.50	4.10	3.41	3.53
C FLUE GAS O_2 AVG.	%	5.24	5.63	5.63	3.40	3.38	3.41	3.43	3.47
B AMBIENT TEMP.	°F	77	64	70	75	73	72	75	62
B AMBIENT REL. HUMIDITY	%	20	38	30	28	24	31	26	22
B BAROMETRIC PRESS.	"Hg	23.97	24.20	24.18	24.03	24.00	24.05	24.03	24.03

B = BOARD DATA
C = COMPUTER DATA
* FEEDER SPEED IN % OF CONTROL SIGNAL

OVERFIRE AIR OPERATION STUDY

BOARD AND COMPUTER DATA

	TEST NO.		17	18	19	20	21	22	23	24
	DATE	1975	10/3	10/3	10/6	10/8	10/10	10/9	10/12	10/5
	TIME		22:30	20:30	19:00	10:30	01:45	01:15	08:15	18:45
C	LOAD	MW	423	430	417	426	356	358	253	266
	MILL DATA									
C	MILL 2-1	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C	MILL 2-2	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C	MILL 2-3	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C	MILL 2-4	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C	MILL 2-5	AMPS	NA	NA	NA	NA	NA	NA	NA	NA
C	COAL AIR TEMP. MILL 2-1	°F	148	149	148	148	148	149	78	148
C	COAL AIR TEMP. MILL 2-2	°F	150	150	148	148	147	148	146	146
C	COAL AIR TEMP. MILL 2-3	°F	146	147	147	147	147	147	146	94
C	COAL AIR TEMP. MILL 2-4	°F	145	145	146	146	145	91	145	145
C	COAL AIR TEMP. MILL 2-5	°F	149	149	149	148	145	149	149	149
B	MILL 2-1 EXH. DISCH.	"H_2O	7.3	7.5	7.5	7.4	6.5	7.5	NA	6.6
B	MILL 2-2 EXH. DISCH.	"H_2O	7.1	6.9	6.5	6.5	6.0	6.4	6.1	NA
B	MILL 2-3 EXH. DISCH.	"H_2O	7.0	7.1	7.3	7.0	6.5	7.3	6.3	6.5
B	MILL 2-4 EXH. DISCH.	"H_2O	7.0	7.0	7.5	7.0	7.0	NA	6.5	6.5
B	MILL 2-5 EXH. DISCH.	"H_2O	7.0	7.3	7.0	7.0	6.6	7.0	6.1	6.3
B	MILL 2-1 SUCTION	"H_2O	-2.1	-2.0	-2.0	-2.0	-2.2	-2.0	NA	-2.4
B	MILL 2-2 SUCTION	"H_2O	-2.0	-2.0	-2.0	-2.0	-2.3	-1.9	-2.4	NA
B	MILL 2-3 SUCTION	"H_2O	-1.9	-1.8	-1.9	-2.0	-2.1	-1.8	-2.4	-2.3
B	MILL 2-4 SUCTION	"H_2O	-2.1	-2.1	-2.1	-2.1	-2.3	NA	-2.5	-2.4
B	MILL 2-5 SUCTION	"H_2O	-2.0	-1.9	-2.1	-2.0	-2.3	-1.9	-2.4	-2.3
B	MILL 2-1 COAL FLOW	10^3LB/HR	67	69	70	66	55	65	NA	55
B	MILL 2-2 COAL FLOW	10^3LB/HR	65	67	67	66	45	69	52	NA
B	MILL 2-3 COAL FLOW	10^3LB/HR	64	65	66	64	56	68	50	49
B	MILL 2-4 COAL FLOW	10^3LB/HR	63	65	66	64	56	NA	49	49
B	MILL 2-5 COAL FLOW	10^3LB/HR	65	66	66	64	58	69	50	50
B	MILL 2-1 FEEDER SPEED *	%	77	79	80	77	63	74	NA	64
B	MILL 2-2 FEEDER SPEED	%	76	79	80	76	54	82	61	NA
B	MILL 2-3 FEEDER SPEED	%	75	78	79	76	67	81	59	58
B	MILL 2-4 FEEDER SPEED	%	76	78	79	75	68	NA	59	59
B	MILL 2-5 FEEDER SPEED	%	77	78	79	75	68	81	60	60
	BURNER TILT	± DEGREES								
B	POSITION LF		0	+21	0	0	0	0	+1	0
B	POSITION LR		+1	+24	+1	+2	+1	+1	+1	0
B	POSITION RF		-2	+20	0	0	-2	0	0	0
B	POSITION RR		0	+23	0	0	0	0	0	0
	MISCELLANEOUS									
B	DRUM LEVEL IN. ± NORM. H_2O LEVEL		0	0	0	0	0	0	0	0
C	FD FAN 2-1	AMPS	207	210	204	208	186	195	NA	168
C	FD FAN 2-2	AMPS	228	232	226	229	199	211	NA	177
C	ID FAN 2-1	AMPS	392	395	391	391	348	354	313	322
C	ID FAN 2-2	AMPS	385	387	385	387	350	352	313	316
B	FLUE GAS SO_2 IN STACK	PPM	73	80	40	80	NA	183	NA	40
B	FLUE GAS NO_x IN STACK	PPM	365	373	373	400	400	400	400	368
C	FLUE GAS COMBUSTIBLES L	%	0.09	0.08	0.09	0.10	0.10	0.10	0.10	0.08
C	FLUE GAS COMBUSTIBLES R	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C	FLUE GAS O_2 L	%	3.75	2.96	2.70	3.50	3.11	2.79	3.07	3.63
C	FLUE GAS O_2 R	%	3.29	3.51	3.63	3.21	3.14	3.73	3.50	4.07
C	FLUE GAS O_2 AVG.	%	3.52	3.24	3.16	3.36	3.12	3.26	3.28	3.85
B	AMBIENT TEMP.	°F	52	56	64	44	40	34	49	64
B	AMBIENT REL. HUMIDITY	%	33	28	28	48	55	67	54	27
B	BAROMETRIC PRESS.	"Hg	24.06	24.03	23.77	23.90	23.96	23.98	23.66	23.96

B = BOARD DATA
C = COMPUTER DATA
* FEEDER SPEED IN % OF CONTROL SIGNAL

WATERWALL CORROSION COUPON DATA SUMMARY

WEIGHT LOSS EVALUATION

BASELINE TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. g	Final Wt. g	Wt. Loss g	Wt. Loss/ Coupon mg/cm^2	Avg. Wt. Loss/ Probe mg/cm^2
1	3	1	192.6190	192.2669	.3521	6.9809	4.7132
		2	193.4064	193.0755	.3309	6.5605	
		3	192.9291	192.7393	.1898	3.7630	
		4	193.5940	193.5159	.0781	1.5484	
2	I	1	198.8883	198.6551	.2332	4.6235	2.6810
		2	201.0329	200.8816	.1513	2.9997	
		3	198.0410	197.9497	.0913	1.8101	
		4	195.5068	195.4417	.0651	1.2907	
3	4	1	192.7191	192.5353	.1838	3.6441	2.8689
		2	194.8814	194.6926	.1888	3.7432	
		3	193.0414	192.9217	.1197	2.3732	
		4	191.3704	191.2839	.0865	1.7150	
4	X	1	191.5552	191.3449	.2103	4.1695	3.4444
		2	192.4223	192.2041	.2182	4.3261	
		3	193.2662	193.1064	.1598	3.1683	
		4	193.4873	193.3807	.1066	2.1135	
5	Z	1	193.6625	193.3771	.2854	5.6584	3.4062
		2	191.0583	190.8201	.2382	4.7226	
		3	192.9096	192.7892	.1204	2.3871	
		4	192.5761	192.5329	.0432	.8565	

Avg. Wt. Loss/Test 3.4266 mg/cm^2

WATERWALL CORROSION COUPON DATA SUMMARY

WEIGHT LOSS EVALUATION

OVERFIRE AIR TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. g	Final Wt. g	Wt. Loss g	Wt. Loss/ Coupon mg/cm^2	Avg. Wt. Loss/ Probe mg/cm^2
1	1	1	191.9684	191.8866	.0818	1.6218	
		2	192.4812	192.3816	.0996	1.9747	1.6709
		3	192.9861	192.9142	.0719	1.4255	
		4	191.5205	191.4367	.0838	1.6614	
2	5	1	193.4934	193.3406	.1528	3.0294	
		2	193.3895	193.1540	.2355	4.6691	3.3858
		3	193.2459	193.0711	.1748	3.4656	
		4	192.2109	192.0909	.1200	2.3791	
3	V	1	193.8941	193.7867	.1074	2.1293	
		2	192.2687	192.1525	.1162	2.3038	2.0268
		3	193.1048	193.0082	.0966	1.9152	
		4	194.6248	194.5362	.0886	1.7589	
4	U	1	192.0607	191.9105	.1502	2.9818	
		2	191.8937	191.7479	.1458	2.8945	3.0340
		3	191.6559	191.5016	.1542	3.0613	
		4	192.3558	192.1947	.1611	3.1982	
5	L	1	202.3430	202.1440	.1990	3.9506	
		2	200.5759	200.4172	.1587	3.1506	3.0608
		3	202.4755	202.3190	.1565	3.1069	
		4	197.4743	197.3718	.1025	2.0349	

Avg. Wt. Loss/Test 2.6357 mg/cm^2

APPENDIX C

TEST DATA & RESULTS
FOR
ALABAMA POWER COMPANY
BARRY STATION
UNIT #2

NO_x TEST DATA SUMMARY

BASELINE STUDY BEFORE MODIFICATION

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14
PURPOSE OF TEST		EXCESS AIR VARIATION													
		CLEAN FURNACE							MOD. DIRTY FURN.			DIRTY FURNACE			
		1/2 LOAD			3/4	FULL LOAD						1/2 LOAD		FULL LOAD	
DATE	1973	11/30	11/30	11/30	1/18/74	11/14	11/28	11/28	11/15	11/19	11/19	12/5	12/4	11/16	11/16
LOAD	MW	66	65	67	93	124	123	123	126	122	124	66	74	125	125
MAIN STEAM FLOW	KG/S	61	62	59	88	112	113	112	114	112	112	59	57	114	113
EXCESS AIR ECON. OUTLET	%	35.5	17.5	58.9	12.6	22.7	11.7	30.8	21.5	13.0	26.0	32.7	51.2	20.7	24.3
THEO. AIR TO FUEL FIRING ZONE	%	130.6	117.1	151.3	109.2	117.9	107.2	125.3	116.9	108.5	120.8	128.0	144.1	115.7	119.2
FUEL ELEVATIONS IN SERVICE		ABC	ABC	ABC	ABC	ALL	ALL	ALL	ALL	ALL	ALL	ABC	ABC	ALL	ALL
FUEL NOZZLE TILT	DEG	+3	+7	+3	+8	+3	0	0	+8	-22	-22	0	0	-22	-22
NOZZLE COMPARTMENT DAMPER POSITION % OPEN — "A"	AUX	20	0	50	30	60	100	100	60	100	100	20	50	100	100
	FUEL	30	30	30	20	20	30	30	30	30	30	30	30	30	30
"B"	AUX	20	0	50	60	100	100	100	100	100	100	20	50	100	100
	FUEL	30	30	30	20	20	30	30	30	30	30	30	30	30	30
"C"	AUX/AUX	20/20	20/10	50/50	80/80	100/100	100/100	100/100	100/100	100/100	100/100	20/20	50/50	100/100	100/100
	FUEL	30	30	30	20	20	30	30	30	30	30	30	30	30	30
"D"	AUX	20	10	50	50	100	100	100	100	100	100	20	50	100	100
	FUEL	0	0	0	0	20	30	30	30	30	30	0	0	30	30
	AUX	0	0	0	0	100	100	100	100	100	100	0	0	100	100
SHO TEMPERATURE	°C	529	498	548	500	539	539	538	548	533	544	518	548	539	543
RHO TEMPERATURE	°C	488	446	517	499	514	524	524	533	510	531	476	508	522	529
UNIT EFFICIENCY	%	88.3	88.2	87.6	89.3	89.0	89.1	89.5	89.6	89.6	89.6	88.3	87.9	89.2	89.3
GAS WT. ENT. A.H.	KG/S	97.8	100.0	114.4	107.2	153.9	160.6	164.4	157.5	139.4	156.9	89.7	102.5	154.4	157.5
NO_x	PPM-0% O_2	631	489	718	429	494	357	664	421	361	581	536	658	499	586
	NG/J	319.3	246.0	362.8	214.0	248.6	181.8	335.1	213.5	178.6	286.1	267.0	327.2	247.7	292.6
SO_2	PPM-0% O_2	2298	2318	1644	1635	1641	1434	1455	1171	2052	2179	2348	2164	1917	1370
	NG/J	1617.0	1622.7	1156.3	1139.1	1150.0	1016.1	1021.8	825.9	1414.4	1493.0	1629.2	1496.8	1322.7	951.8
CO	PPM-0% O_2	24	142	8	39	31	153	33	46	432	5	298	220	41	34
	NG/J	7.5	43.5	24.8	11.9	9.6	47.3	10.1	14.1	130.2	1.6	90.3	66.9	12.4	10.3
HC	PPM-0% O_2	0.144	0.160	0.0	0.0	0.509	0.0	0.0	0.61	0.128	1.54	0.0	0.0	0.513	0.397
O_2	% AH IN	5.6	3.2	7.9	2.4	4.0	2.3	5.0	3.8	2.5	4.4	5.3	7.2	3.7	4.2
	% AH OUT	7.3	5.6	9.1	5.1	6.2	4.6	6.9	5.3	4.6	6.6	7.0	8.6	6.0	6.4
CARBON LOSS IN FLYASH	%	0.29	0.97	0.17	0.96	0.48	0.57	0.20	0.16	0.27	0.05	0.58	0.20	0.17	0.10

NO_X TEST DATA SUMMARY

BIASED FIRING STUDY

TEST NO.		15	16	17	18	19	20	21	22	23	24
		← BIASED FIRING - 1 FUEL ELEV. OUT OF SERVICE - AIR DAMPERS OPEN →									
PURPOSE OF TEST		1/2	3/4	← MAX. LOAD →				3/4	← 1/2 LOAD →		
DATE		1/19/74	1/18/74	12/3/73	12/4/73	12/5/73	12/6/73	1/18/74	1/19/74	1/19/74	1/19/74
LOAD	MW	66	96	100	103	99	102	94	64	64	66
MAIN STEAM FLOW	KG/S	55	82	87	89	89	87	86	58	59	56
EXCESS AIR ECON. OUT	%	50.1	26.7	21.1	22.2	21.8	24.2	29.0	48.0	47.0	47.0
THEO. AIR TO FUEL FIRING ZONE	%	105.8	121.7	116.5	117.5	117.2	94.7	97.3	112.5	141.4	141.3
FUEL ELEVATIONS IN SERVICE		ABC	ABC	ABC	ABD	ACD	BCD	BCD	BCD	ACD	ABD
FUEL NOZZLE TILT	DEG	-9	0	-15	-15	-10	-5	+10	0	0	-15
NOZZLE COMPARTMENT DAMPER POSITION % OPEN "A" AUX		50	50	50	50	50	100	100	100	50	50
"A" FUEL		20	20	30	30	30	100	100	100	20	20
"B" AUX		50	50	50	50	100	50	50	50	100	50
"B" FUEL		20	20	30	30	100	30	20	20	100	20
"C" AUX/AUX		50/50	50/50	50/50	50/100	50/50	50/50	50/50	50/50	50/50	50/100
"C" FUEL		20	20	30	100	30	30	20	20	20	100
"D" AUX		50	50	50	50	50	50	50	50	50	50
"D" FUEL		100	100	100	30	30	30	20	20	20	20
"D" AUX		100	100	100	50	50	50	50	50	50	50
SHO TEMPERATURE	°C	546	539	529	543	523	544	512	501	507	544
RHO TEMPERATURE	°C	496	506	501	520	486	515	469	448	454	513
UNIT EFFICIENCY	%	87.9	89.3	89.1	89.3	88.9	88.8	89.6	87.8	87.9	87.7
GAS WT. ENTERING AH	KG/S	94.7	119.4	121.9	126.4	118.9	125.3	120.8	100.0	100.3	98.9
NO_x	PPM-0% O_2	594	543	397	373	387	285	331	520	485	609
	MG/J	288.0	272.8	200.6	189.2	189.9	143.1	166.2	268.5	249.1	306.2
SO_2	PPM-0% O_2	1721	1682	2422	2553	2292	2277	1566	1861	2245	1807
	UG/J	1161.0	1175.6	1704.6	1799.9	1562.8	1591.0	1093.4	1335.9	1602.7	1263.0
CO	PPM-0% O_2	33	29	46	38	35	27	31	29	22	28
	MG/J	9.8	8.9	14.0	11.9	10.6	8.1	9.5	9.1	7.0	8.4
HC	PPM-0% O_2	0.0	0.0	0.0	0.012	0.012	0.0	0.0	0.0	0.0	0.0
O_2	% AH IN	7.1	4.5	3.7	3.9	3.8	4.2	4.8	6.9	6.8	6.8
	% AH OUT	8.5	7.2	6.1	5.8	6.3	7.3	8.4	8.4	8.6	6.9
CARBON LOSS IN FLYASH	%	0.32	0.34	0.46	0.37	0.42	0.25	0.30	0.20	0.11	0.21

Alabama Power Company
Barry #2

NO_x TEST DATA SUMMARY

C-E Power Systems
Field Testing and
Performance Results

BASELINE STUDY AFTER MODIFICATION

TEST NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14
		← EXCESS AIR VARIATION - CLEAN FURN. →							← EA VAR. - MOD. DIRTY →			← EA VAR. - DIRTY FURN. →			
PURPOSE OF TEST		← 1/2 LOAD →			3/4	← MAXIMUM LOAD →						← 1/2 LOAD →		← MAX LOAD →	
DATE		6/25/74	6/25/74	6/25/74	6/27/74	6/19/74	6/27/74	6/27/74	6/20/74	6/20/74	6/28/74	6/26/74	6/26/74	6/28/74	6/28/74
LOAD	MW	62	62	64	92	131	127	125	130	129	125	65	68	126	125
MAIN STEAM FLOW	KG/SEC	61	59	60	87	125	122	117	122	124	119	68	61	120	118
EXCESS AIR ECON. OUTLET	%	33.5	16.0	64.7	15.5	21.0	12.4	25.4	17.8	12.1	26.6	30.9	63.1	22.0	25.9
THEO. AIR TO FUEL FIRING ZONE	%	127.1	113.4	155.4	111.0	115.3	107.1	119.5	112.3	106.9	120.5	124.6	154.0	116.2	119.9
FUEL ELEV. IN SERVICE		ABC	ABC	ABC	ABC	ALL	ALL	ALL	ALL	ALL	ALL	ABC	ABC	ALL	ALL
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FUEL NOZZLE TILT	DEG	3	6	-14	2	-13	-3	-22	-21	-17	-16	-16	-16	-6	-6
NOZZLE COMP. DAMPER POSITION % OPEN — OFA		0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFA		0	0	0	0	0	0	0	0	0	0	0	0	0	0
AUX		20	0	50	30	80	100	100	80	80	100	20	50	100	100
"A" FUEL		30	30	30	20	30	30	35	30	30	30	30	30	30	30
AUX		20	0	50	60	100	100	100	100	100	100	20	50	100	100
"B" FUEL		30	30	30	20	30	30	35	30	30	30	30	30	30	30
AUX/AUX		20/20	10/10	50/50	80/80	100/100	100/100	100/100	100/100	100/100	100/100	20/20	50/50	100/100	100/100
"C" FUEL		30	30	30	20	30	30	35	30	30	30	30	30	30	30
AUX		20	10	50	50	100	100	100	100	100	100	20	50	100	100
"D" FUEL		0	0	0	0	30	30	35	30	30	30	0	0	30	30
AUX		0	0	0	0	100	100	100	100	100	100	0	0	100	100
SHO TEMPERATURE	°C	492	468	536	504	528	524	518	526	528	524	507	531	524	529
RHO TEMPERATURE	°C	435	402	499	466	488	487	480	486	483	480	457	498	496	499
UNIT EFFICIENCY	%	88.4	88.8	87.4	89.8	88.4	89.2	89.5	89.0	88.9	89.5	89.3	88.0	89.0	89.4
GAS WT. ENT. AIR HTR.	KG/SEC	93	75	115	111	165	152	155	157	151	162	101	116	160	162
NO_x	PPM-0% O_2	444	335	640	327	404	330	477	470	334	431	373	626	391	431
	NG/J	221.9	167.4	319.8	163.4	202.1	165.3	238.8	235.3	167.0	215.4	186.8	312.9	195.6	215.4
SO_2	PPM-0% O_2	3678	3621	2611	2634	2251	2677	2707	1941	2482	2500	2558	2461	2564	2629
	UG/J	256.0	252.0	181.7	183.3	156.7	186.3	188.4	135.1	172.7	174.0	178.0	171.3	178.4	183.0
CO	PPM-0% O_2	28	376	35	110	26	127	22	24	97	24	26	24	23	23
	NG/J	8.4	114.4	10.6	33.4	8.0	38.7	6.6	7.4	29.6	7.2	8.0	7.3	7.1	7.0
HC	PPM-0% O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O_2	% AH IN	5.4	3.0	8.4	2.9	3.7	2.4	4.3	3.2	2.3	4.5	5.0	8.2	3.9	4.4
	% AH OUT	7.4	5.5	9.7	5.5	7.4	5.8	7.0	6.8	6.2	7.5	7.6	10.8	7.3	7.2
CARBON LOSS IN FLY ASH	%	0.29	0.23	1.06	0.11	0.75	0.51	0.74	0.22	0.42	0.61	0.17	0.05	0.36	0.25

NO_x TEST DATA SUMMARY

OFA LOCATION, RATE AND VELOCITY VARIATION

TEST NO.		15	16	17	18A	19	20	21	22	23
		← OFA DAMPER POSITION VARIATION →								
PURPOSE OF TEST		← 3/4 LOAD →								
DATE		7/10/74	7/10/74	7/10/74	7/12/74	7/11/74	7/11/74	7/12/74	7/12/74	7/12/74
LOAD	MW	97	98	100	100	100	100	102	102	102
MAIN STEAM FLOW	KG/SEC	93	94	94	96	94	96	95	95	96
EXCESS AIR ECON. OUT	%	28.5	27.1	25.6	26.6	24.8	25.4	25.4	27.9	28.1
THEO. AIR TO FUEL FIRING ZONE	%	114.5	96.7	95.8	84.8	89.3	100.5	117.4	90.4	96.9
FUEL ELEVATIONS IN SERVICE		BCD	BCD	BCD	BCD	BCD	BCD	ABC	ABC	ABC
OFA NOZZLE TILT	DEG	0	0	0	0	0	0	0	0	0
FUEL NOZZLE TILT	DEG	-5	-5	-5	-4	-4	-4	-4	-4	-4
OFA		0	100	0	100	50	0	0	100	50
OFA		0	0	100	100	50	0	0	100	50
AUX		0	0	0	0	0	100	100	100	50
"A" FUEL		0	0	0	0	0	0	100	100	50
AUX		50	50	50	50	50	50	50	50	50
"B" FUEL		30	30	30	30	30	30	30	30	30
AUX/AUX		50/50	50/50	50/50	50/50	50/50	50/50	50/50	50/50	50/50
"C" FUEL		30	30	30	30	30	30	30	30	30
AUX		50	50	50	50	50	50	50	50	50
"D" FUEL		30	30	30	30	30	30	0	0	0
AUX		50	50	50	50	50	50	0	0	0
SHO TEMPERATURE	°C	518	510	514	524	521	524	532	524	521
RHO TEMPERATURE	°C	457	452	457	476	486	479	498	491	485
UNIT EFFICIENCY	%	90.0	89.8	89.7	89.6	89.3	90.2	90.1	89.0	89.1
GAS WT. ENT. AH	KG/SEC	127	124	123	129	130	130	132	137	137
NO_x	PPM-0% O_2	345	254	254	229	232	323	483	329	336
	NG/J	178.7	127.3	127.3	114.4	116.1	161.7	241.7	164.6	168.1
SO_2	PPM-0% O_2	1892	1973	2092	2391	2684	1821	1814	2259	2417
	UG/J	131.6	137.3	145.6	166.8	186.8	126.8	126.2	157.2	168.2
CO	PPM-0% O_2	28	30	32	48	39	29	25	26	25
	NG/J	8.6	9.1	9.9	14.6	11.9	8.8	7.7	7.8	7.7
HC	PPM-0% O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O_2	% AH IN	4.7	4.6	4.4	4.5	4.3	4.3	4.3	4.7	4.7
	% AH OUT	6.5	6.5	6.1	6.3	6.1	6.1	6.1	6.5	6.7
CARBON LOSS IN FLY ASH	%	0.51	0.59	0.63	0.54	0.32	0.49	0.46	0.54	0.60

NO_x TEST DATA SUMMARY

OFA TILT AND LOAD VARIATION

TEST NO.		24	25	26	27	28	29	30	31	32	33	34	35
		← OFA & FUEL NOZZLE TILT VARIATION →						← LOAD VARIATION AT OPTIMUM COND. →					
PURPOSE OF TEST		← FULL LOAD →						MAX	3/4	1/2	MAX	3/4	1/2
DATE		7/29/74	7/29/74	7/29/74	7/29/74	7/29/74	7/29/74	7/30/74	7/31/74	7/31/74	7/31/74	7/31/74	8/1/74
LOAD	MW	124	124	124	125	125	124	125	97	65	122	95	64
MAIN STEAM FLOW	KG/S	113	116	114	113	115	116	116	87	57	114	86	57
EXCESS AIR ECON. OUT	%	25.9	23.7	25.1	22.3	20.2	23.7	21.6	25.2	46.9	27.4	27.4	45.9
THEO. AIR TO FUEL FIRING ZONE	%	94.2	92.4	93.2	94.5	89.6	92.6	90.7	89.4	88.5	94.6	90.6	88.5
FUEL ELEVATIONS IN SERVICE		ALL	ALL	ALL	ALL	ALL	ALL	ALL	ABC	AB	ALL	ABC	AB
OFA NOZZLE TILT	DEG	0	0	0	-30	-30	+30	0	-12	0	-22	-22	-10
FUEL NOZZLE TILT	DEG	-5	-23	+19	-5	+22	-21	-4	-16	-5	-22	-22	-15
NOZZLE COMPARTMENT DAMPER POSITION % OPEN — OFA		100	100	100	100	100	100	100	100	100	100	100	100
OFA		100	100	100	100	100	100	100	100	100	100	100	100
AUX		100	100	100	100	100	100	100	100	100	100	100	100
"A" FUEL		100	100	100	100	100	100	100	100	100	100	100	100
AUX		50	50	50	50	50	50	50	50	50	50	50	50
"B" FUEL		30	30	30	30	30	30	30	30	30	30	30	30
AUX/AUX		50/50	50/50	50/50	50/50	50/50	50/50	50/50	50/50	50/0	50/50	50/50	50/50
"C" FUEL		30	30	30	30	30	30	30	30	0	30	30	0
AUX		50	50	50	50	50	50	50	50	0	50	50	0
"D" FUEL		30	30	30	30	30	30	30	0	0	30	0	0
AUX		50	50	50	50	50	50	50	0	0	50	0	0
SHO TEMPERATURE	°C	538	521	524	527	524	521	538	525	535	521	506	512
RHO TEMPERATURE	°C	532	508	527	533	535	505	536	514	514	521	493	493
UNIT EFFICIENCY	%	89.6	89.3	88.9	89.3	88.6	89.4	89.0	89.1	89.2	89.0	88.2	89.0
GAS WT. ENTERING AH	KG/S	152	157	163	155	163	151	159	127	95	162	131	91
NO_x	PPM-0% O_2	339	290	368	344	404	285	339	338	396	333	291	313
	NG/J	169.6	145.5	183.9	172.2	202.1	142.4	169.6	169.1	197.8	166.5	145.2	156.4
SO_2	PPM-0% O_2	2450	2920	3310	3160	3370	3240	1680	1730	1740	2430	2490	2420
	UG/J	170.5	203.3	230.4	219.9	234.5	225.5	116.9	120.5	121.1	169.2	173.3	166.2
CO	PPM-0% O_2	25	27	32	22	28	49	26	26	24	25	26	25
	NG/J	7.7	8.3	9.7	6.7	8.6	15.0	8.0	8.0	7.4	7.5	8.0	7.6
HC	PPM-0% O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O_2	% AH IN	4.4	4.1	4.3	3.9	3.6	4.1	3.8	4.3	6.8	4.6	4.6	6.7
	% AH OUT	5.9	6.0	6.2	6.0	5.8	6.4	5.3	5.7	8.2	6.3	6.8	8.4
CARBON LOSS IN FLY ASH	%	0.37	0.37	0.40	0.29	0.29	0.49	0.61	0.39	0.32	0.24	0.33	0.15

WATERWALL ABSORPTION RATES, KG-CAL/HR-CM^2

RIGHT WALL CENTERLINE TUBE RATES

TC #	1	3	5	7	9	19	22	44	47	57	60	62	64
ELEVATION	118'-6"	107'-6"	96'-6"	85'-6"	74'-6"	69'-6"	64'-7"	59'-7"	54'-9"	49'-11"	45'-7"	35'-7"	25'-7"
TEST 1	2.02	3.56	7.49	8.81	10.93	9.07	1.28	---	---	8.54	4.08	3.30	---
2	2.36	3.64	8.63	12.07	13.13	9.95	.86	---	---	6.51	5.99	3.12	---
3	1.33	2.85	5.18	7.02	8.08	7.55	.83	---	---	9.66	9.93	4.13	---
4	3.01	5.36	12.23	1.25	2.76	14.88	5.10	---	---	13.29	7.73	4.31	---
5	3.78	7.19	10.90	10.90	22.55	7.46	6.93	---	---	18.85	20.96	12.49	---
6	4.41	7.30	13.66	1.83	3.37	16.04	7.83	---	---	20.81	14.45	10.21	---
7	3.73	5.04	10.06	1.19	2.18	7.67	8.73	12.18	---	27.78	11.38	14.56	---
8	4.59	8.28	11.45	8.54	21.78	5.11	4.06	---	---	10.13	13.04	15.70	---
9	6.26	9.96	14.99	15.52	23.46	15.52	6.26	---	---	8.63	12.34	15.26	---
10	5.14	5.66	12.27	7.51	6.45	10.15	9.36	---	---	24.18	6.98	12.80	---
11	4.16	4.95	6.26	6.79	6.53	4.43	6.00	---	---	11.56	6.53	6.53	---
12	4.15	5.46	6.51	6.51	5.98	5.72	5.72	---	---	11.53	7.56	7.83	---
13	4.95	6.53	13.14	9.96	13.94	17.38	15.00	---	---	25.05	10.76	12.61	---
14	4.44	4.96	11.30	9.97	17.66	14.74	15.01	---	---	24.00	15.28	12.62	---
15	4.12	5.17	9.66	.37	3.34	7.80	13.36	---	---	3.34	10.71	10.98	---
16	5.25	5.77	8.15	2.38	7.62	10.26	12.38	---	---	3.42	8.68	9.47	---
17	6.47	7.26	9.90	3.33	6.99	10.96	13.61	---	---	3.84	10.70	12.55	---
18	3.61	4.91	9.92	.16	13.37	13.37	10.45	---	---	18.67	17.34	8.07	---
19	4.39	5.44	10.19	2.32	4.65	9.40	5.17	---	---	14.43	9.92	10.45	---
20	3.14	5.23	10.24	.64	4.18	2.63	12.1	---	---	20.58	18.20	9.72	---
21	4.00	5.31	12.45	.49	2.71	2.20	12.98	---	---	15.10	10.33	4.53	---
22	3.49	5.32	11.40	1.46	2.46	1.96	11.93	---	---	15.11	9.81	3.24	---
23	2.67	5.00	11.87	.91	2.67	1.90	11.87	---	---	15.32	10.02	3.70	---
24	4.76	5.28	12.68	9.24	7.92	3.98	8.18	---	---	23.80	12.68	7.92	---
25	3.00	5.08	10.63	6.66	6.13	2.48	11.95	---	---	32.55	20.43	13.01	---
26	4.61	6.71	14.66	13.07	19.69	2.80	12.80	---	---	15.45	10.15	4.35	---
27	4.22	6.32	8.43	10.02	15.85	10.81	11.34	---	---	18.76	15.05	12.40	---
28	7.16	8.22	11.93	14.04	17.22	11.66	12.72	---	---	13.25	11.93	7.43	---
29	5.42	7.80	8.32	9.91	11.24	9.91	12.03	---	---	27.63	17.33	17.86	---
30	7.55	9.14	9.93	8.08	3.87	6.23	9.14	---	---	4.65	7.02	8.34	---
31	7.07	7.60	8.65	6.80	7.07	11.56	7.07	---	---	18.98	16.07	9.98	---
32	5.21	6.00	7.05	6.00	5.47	8.90	4.42	---	---	14.73	12.87	7.05	---
33	7.27	7.53	7.80	7.80	7.27	11.24	14.15	---	---	24.47	14.95	16.54	---
34	7.52	7.52	8.84	8.05	8.05	9.37	11.22	---	---	15.47	13.35	14.14	---
35	6.60	5.81	6.60	6.33	6.33	8.18	7.92	---	---	10.56	17.45	7.92	---

WATERWALL ABSORPTION RATES, KG-CAL/HR-CM^2

FRONT WALL CENTERLINE TUBE RATES

TC #	2	4	6	8	13	38	51	61	63
ELEVATION	107'-6"	96'-6"	85'-6"	74'-6"	69'-6"	59'-7"	49'-11"	35'-7"	25'-7"
TEST 1	6.44	7.49	11.99	18.08	10.93	----	10.13	3.04	2.52
2	6.78	8.89	14.72	16.31	11.01	---	8.89	2.88	2.36
3	5.18	4.92	7.55	8.08	8.61	---	13.11	4.66	1.33
4	10.11	11.96	7.46	24.67	9.84	---	14.62	4.05	3.01
5	11.16	9.57	10.37	24.92	10.10	---	19.11	12.75	7.46
6	12.33	12.60	18.69	27.14	12.86	---	20.28	13.39	4.67
7	9.26	8.47	12.44	10.85	6.35	---	23.56	18.55	9.53
8	10.92	7.48	10.66	22.31	16.76	---	7.22	15.70	9.60
9	13.67	9.96	10.48	25.83	14.20	---	7.05	17.38	7.84
10	11.48	4.61	15.98	14.92	7.24	---	5.40	15.72	5.66
11	5.21	4.95	6.79	6.53	4.95	---	7.85	6.26	6.26
12	5.46	5.72	6.77	6.25	5.46	---	8.88	8.09	7.56
13	12.88	6.26	7.84	11.56	6.79	---	7.58	14.47	5.21
14	10.77	4.96	8.39	11.56	5.48	---	12.36	14.74	5.22
15	8.07	5.17	14.16	11.77	2.57	---	2.32	18.13	6.22
16	7.62	5.77	10.79	15.83	4.46	---	2.92	15.83	7.62
17	8.05	6.99	12.29	14.41	5.68	---	4.63	16.26	9.37
18	8.07	5.17	14.16	11.25	7.28	---	10.19	9.92	6.49
19	9.13	4.91	12.84	6.22	8.86	---	9.66	10.98	5.44
20	8.66	9.98	11.30	22.69	9.98	---	9.19	16.07	4.97
21	10.33	11.39	17.22	21.98	8.48	---	3.23	5.58	3.48
22	10.34	10.07	18.29	15.90	4.80	---	2.21	4.80	2.45
23	10.02	7.64	16.91	19.02	13.46	---	2.40	5.00	2.67
24	10.56	8.18	9.51	15.07	6.34	---	16.40	12.95	5.02
25	10.10	8.24	6.66	15.66	10.10	---	19.64	20.43	9.57
26	12.27	10.68	19.96	19.96	7.51	---	12.80	5.40	4.35
27	9.22	7.64	14.26	8.16	7.11	---	8.69	14.26	3.44
28	9.54	9.81	12.99	12.19	9.54	---	6.11	8.75	6.90
29	9.91	8.06	11.24	10.18	10.44	---	18.92	20.77	9.38
30	9.66	9.66	13.38	25.81	13.90	---	8.61	8.87	7.55
31	7.86	8.12	11.56	8.12	7.60	---	7.33	11.56	8.12
32	6.00	5.21	8.10	6.26	5.21	---	5.21	7.84	5.73
33	8.85	7.00	7.00	18.66	6.48	---	21.57	19.98	12.56
34	8.31	6.99	6.99	10.96	5.68	---	22.08	14.94	10.43
35	7.12	5.81	5.54	7.39	3.20	---	7.92	8.18	7.65

WATERWALL ABSORPTION RATES, KG-CAL/HR-CM^2

	Right Wall Horizontal Average Tube Rates			Rear Wall Horizontal Average Tube Rates	Left Wall Horizontal Average Tube Rates	Front Wall Horizontal Average Tube Rates		
TC #	17-21	42-46	55-59	23-29	30-34	10-16	35-41	48-54
Elevation	69'-8"	59'-7"	49'-11"	59'-7"	59'-7"	69'-6"	59'-7"	49'-11"
TEST 1	8.65	9.54	8.28	5.78	11.67	11.94	10.31	8.24
2	9.53	9.16	5.82	4.97	12.23	12.34	11.11	6.92
3	7.97	9.27	9.58	4.79	10.72	8.56	8.85	11.87
4	13.51	11.84	7.90	6.01	10.20	13.20	15.68	9.39
5	5.67	9.98	10.64	12.22	17.10	16.33	17.34	18.73
6	14.40	15.11	16.75	8.07	14.53	17.01	17.41	12.26
7	7.84	11.96	18.26	8.21	9.04	10.90	16.12	17.13
8	3.66	7.63	7.10	9.22	14.12	13.80	20.10	20.73
9	7.38	10.05	6.53	14.01	14.83	16.45	18.43	17.94
10	8.20	16.31	15.28	12.13	19.48	14.92	18.98	13.86
11	4.84	5.09	9.18	9.10	4.79	6.35	7.59	7.76
12	5.62	5.46	9.16	8.74	6.19	5.72	6.38	8.75
13	10.18	14.34	15.70	13.94	16.06	12.93	17.64	13.27
14	8.34	15.34	17.92	14.06	16.81	13.91	18.09	13.66
15	9.70	11.38	9.41	10.62	18.29	10.77	15.70	8.54
16	11.70	10.93	12.13	10.46	18.37	12.74	16.45	9.09
17	13.77	10.44	11.95	10.44	16.47	13.17	16.88	10.35
18	7.31	12.77	16.73	6.07	14.48	10.81	17.16	16.12
19	6.96	4.61	8.72	7.52	7.50	9.70	14.43	9.54
20	2.89	9.52	13.62	6.42	7.77	10.92	16.25	9.16
21	2.76	10.14	13.51	5.51	13.72	15.85	18.76	8.42
22	2.52	9.36	13.43	6.28	14.85	13.48	17.66	7.74
23	3.19	10.16	13.64	6.04	15.54	19.17	17.12	12.28
24	12.22	12.22	8.55	9.74	15.86	11.89	16.08	9.18
25	9.63	14.00	22.35	9.61	14.18	12.04	16.76	13.81
26	10.54	12.21	10.25	7.53	14.45	14.22	13.95	10.17
27	10.81	12.40	14.70	8.14	13.52	9.88	10.03	8.88
28	12.94	14.44	12.81	9.21	17.60	13.52	14.80	7.26
29	11.34	16.07	20.06	12.18	12.72	12.30	16.76	17.63
30	9.52	10.66	4.48	12.01	11.47	14.00	16.51	10.51
31	7.71	10.38	17.84	10.85	8.85	7.33	16.78	9.14
32	6.32	7.98	14.02	8.53	9.02	5.21	14.51	8.11
33	10.08	17.06	18.21	10.44	10.66	8.33	16.05	16.05
34	8.21	14.67	13.35	9.11	9.27	8.10	13.79	16.57
35	7.65	10.76	10.12	9.05	9.50	7.75	9.20	9.42

WATERWALL CORROSION COUPON DATA SUMMARY

WEIGHT LOSS EVALUATION

BASELINE TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. GR.	Final Wt. GR.	Wt. Loss GR.	Wt. Loss/ Coupon MG/CM^2	Avg. Wt. Loss/ Probe MG/CM^2
1	I	1	199.2937	199.1341	.1596	3.1643	2.9392
		2	201.3871	201.2135	.1736	3.4418	
		3	198.3883	198.2384	.1499	2.9719	
		4	195.8045	195.6946	.1099	2.1789	
2	J	1	199.1977	199.0534	.1443	2.8609	2.8088
		2	199.6807	199.5009	.1798	3.5647	
		3	202.8649	202.7226	.1423	2.8213	
		4	202.3445	202.2442	.1003	1.9885	
3	E	1	199.0122	198.8632	.1490	2.9541	2.13475
		2	202.2508	202.1171	.1337	2.6507	
		3	201.9826	201.8976	.0850	1.6852	
		4	199.6584	199.5954	.0630	1.249	
4	L	1	202.5778	202.5080	.0698	1.3838	1.91965
		2	200.8579	200.7484	.1095	2.1769	
		3	202.7075	202.5924	.1151	2.282	
		4	197.7676	197.6750	.0926	1.8359	
5	K	1	199.5913	---	---	---	3.38826
		2	197.4684	197.2730	.1954	3.874	
		3	194.9513	194.7783	.1730	3.4299	
		4	202.0694	201.9251	.1443	2.8609	

Avg. Wt. Loss/Test 2.6381 MG/CM^2

WATERWALL CORROSION COUPON DATA SUMMARY

WEIGHT LOSS EVALUATION

BIASED FIRING TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. GR.	Final Wt. GR.	Wt. Loss GR.	Wt. Loss/ Coupon MG/CM^2	Avg. Wt. Loss/ Probe MG/CM^2
1	B	1	197.9531	197.6484	.3047	6.0411	
		2	202.1660	201.8659	.3001	5.9499	5.8795
		3	198.3393	198.0383	.3010	5.9678	
		4	200.5603	200.2799	.2804	5.5593	
2	Q	1	199.3158	199.1437	.1721	3.4121	
		2	196.2751	196.0480	.2271	4.5026	4.3777
		3	202.8709	202.5541	.3168	6.2810	
		4	200.2327	200.0655	.1672	3.3150	
3	R	1	198.8940	198.7626	.1314	2.6051	
		2	199.8790	199.6842	.1948	3.8622	3.4081
		3	196.0683	195.8721	.1962	3.8899	
		4	199.3342	199.1690	.1652	3.2753	
4	M	1	199.5078	199.3628	.1450	2.8748	
		2	198.7039	198.4853	.2186	4.3341	3.8201
		3	198.3125	198.1121	.2004	3.9732	
		4	200.8838	200.6771	.2067	4.0981	
5	D	1	197.9655	197.7001	.2654	5.2619	
		2	202.9412	202.5809	.3603	7.1435	5.7289
		3	199.1306	198.7976	.3330	6.6022	
		4	198.2205	198.0234	.1971	3.9078	

Avg. Wt. Loss/Test 4.6429 MG/CM^2

WATERWALL CORROSION COUPON

DATA SUMMARY

WEIGHT LOSS EVALUATION

OVERFIRE AIR TEST

Probe Loc.	Probe No.	Coupon No.	Initial Wt. GR.	Final Wt. GR.	Wt. Loss GR.	Wt. Loss/ Coupon MG/CM^2	Avg. Wt. Loss/ Probe MG/CM^2
1	S	1	200.7678	200.5465	.2213	4.3876	
		2	196.0684	195.8121	.2563	5.0815	4.5244
		3	199.6433	199.3849	.2584	5.1235	
		4	197.8187	197.6419	.1768	3.5053	
2	T	1	200.7026	199.1437	.2802	5.5554	
		2	---	---	---	3.3540	3.9044
		3	593.7075	593.2000	.5075	3.3540	
		4	---	---	---	3.3540	
3	F	1	199.1897	198.9156	.2741	5.4344	
		2	199.4476	199.1351	.3125	6.1958	6.0401
		3	199.3119	198.9858	.3261	6.4654	
		4	199.0463	198.7404	.3059	6.0649	
4	N	1	202.8354	202.6125	.2234	4.4292	
		2	201.2249	200.9784	.2465	4.8872	3.7656
		3	---	---	---	2.8729	
		4	397.4898	397.2000	.2898	2.8729	
5	2	1	---	---	---	---	
		2	191.8528	191.6484	.2044	4.0525	3.9752
		3	192.7875	192.5909	.1966	3.8979	
		4	---	---	---	---	

Avg. Wt. Loss/Test 4.4419 MG/CM^2

APPENDIX D

COMPFLOW
WINDBOX COMPARTMENT AIR FLOW
DISTRIBUTION COMPUTER PROGRAM

APPENDIX D
COMPFLOW - WINDBOX
COMPARTMENT AIR FLOW DISTRIBUTION COMPUTER PROGRAM

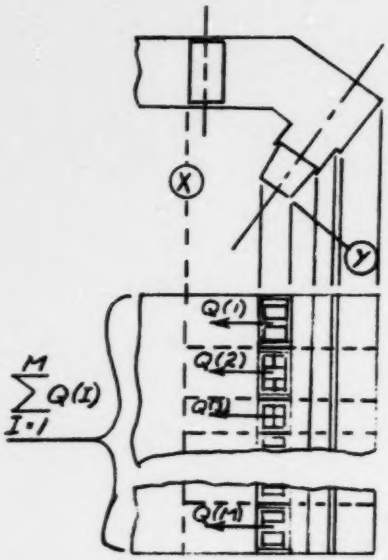
INTRODUCTION

A description of COMPAIR, a computer program which calculates the windbox assembly air flow distribution, was presented in Reference 1. The program has been subsequently found to be deficient; the approach taken in the calculation of the compartment loss coefficient resulted in operational difficulties in certain cases. The program was revised to eliminate this problem.

The revised program, COMPFLOW, is described herein. The basic assumptions and limitations of the calculation method are outlined and discussed. Program runs for two tests conducted at Barry #2 are included.

ANALYSIS

Consideration will be initially focused on those cases where the air flow to each compartment is supplied solely by the windbox.



Assumptions:

1. Constant total pressure at compartment inlet plane, i.e., P_{T_X} = const.
2. Constant density, i.e., R(I) = R = const.
3. Constant static pressure at nozzle exit plane, i.e., P_{s_y} = const.
4. Fully turbulent flow, i.e., Head Loss $\approx$ (Velocity)^2.

Utilizing these assumptions, it follows that

$$2 * \left[\frac{P_{T_X} - P_{s_y}}{R}\right] = K(I) * \left[\frac{Q(I)}{A(I)}\right]^2 = \text{const.} \quad \text{- - - - - - - - - - - -(1)}$$

Where K(I) = loss coef. for Compartment "I"
Q(I) = volume rate of flow for Compartment "I"
A(I) = nozzle exit area of Compartment "I"

Equation (1) yields

$$\frac{Q(I)}{\sum_{I=1}^{M} Q(I)} = \frac{A(I)/\sqrt{K(I)}}{\sum_{I=1}^{M} A(I)/\sqrt{K(I)}} \quad \text{----------(2)}$$

By definition

$$P_{T_y}(I) = P_{s_y} + \frac{R}{2} * \left[\frac{Q(I)}{A(I)}\right]^2 \quad \text{----------(3)}$$

Using Equations (1) and (3), we have

$$2 * \left[\frac{P_{T_X} - P_{T_y}(I)}{R}\right] = 2 * \left[\frac{P_{T_X} - P_{s_y}}{R}\right] - \left[\frac{Q(I)}{A(I)}\right]^2 = [K(I) - 1] * \left[\frac{Q(I)}{A(I)}\right]^2 \quad \text{----------(4)}$$

In order to arrive at a relation for K(I), the windbox compartment total pressure loss will be set equal to the sum of its component losses, i.e.,

$$2 * \left[\frac{P_{T_X} - P_{T_y}(I)}{R}\right] = [K_D(I) + K_\beta(I) + K_{90}(I) + K_f(I)] * \left[\frac{Q(I)}{B(I)}\right]^2 + K_N(I) * \left[\frac{Q(I)}{A(I)}\right]^2 \quad \text{----------(5)}$$

Where B(I) = inlet flow area of Compartment "I"

Assumption (5): The values listed below, which allow for no interaction, adequately represent the compartment total pressure loss.

LOSS	VALUE	COMMENT	REFERENCE
Miter bend, $K_\beta(I)$	0.3	Typical, $\beta = 45°$	2
90° bend, $K_{90}(I)$	1.2	-----	2
Friction, $K_f(I)$	0.1	$f \approx 0.02$, $\frac{L}{D} \leq 5$; $K_f = f\frac{L}{D}$	2
Nozzle, $K_N(I)$	0	$K_N = \frac{1}{C_V} - 1$; Assume $C_V = 1$	3
Damper, $K_D(I)$	Figure 1	Assumed to include inlet loss	4

Using the above values, Equations (4) and (5) yield

$$K(I) = 1 + [1.6 + K_D(I)] * \left[\frac{A(I)}{B(I)}\right]^2 \quad \text{----------(6)}$$

For coal fired units the mill air must be taken into account. Using Equation (2) for the secondary air flow, it follows that

$$\frac{W(I)}{W1 + W2} = \frac{\left[\dfrac{A(I)/\sqrt{K(I)}}{\sum_{I=1}^{M} A(I)/\sqrt{K(I)}}\right] * W1 + X(I) * W2}{W1 + W2} \qquad \text{----------(7)}$$

where W(I) = mass rate of flow to Compartment "I"
W1 = total windbox air to corner
W2 = total mill air to corner
X(I) = fraction of mill air to Compartment "I"

Figure 1 and Equations (6) and (7) constitute the basis of COMPFLOW.

Note that if some other source of air were available to the windbox assembly, Equation (7) would yield the flow distribution with adjustments in the definitions of W2 and X(I).

Note also that if there is no corner to corner biasing of compartment dampers, Equation (7) may, to a very good approximation, be regarded on a furnace/elevation basis.

PROGRAM DESCRIPTION

A description of the program input is as follows:

Input

Fuel and Air Compartment Geometry

Number of Compartments
Width of Compartments
Height of Individual Compartments
Number of Dampers per Compartment
Nozzle Exit Area per Compartment

Test Data

Percent Excess Air
Total Air Flow
Compartment Damper Positions
Fuel Elevations in Service

Typical program outputs for Alabama Power Co., Barry #2, tests 5 and 20, are shown on Figure 2. These runs represent both normal and overfire air operation. A definition of the output is shown on Figure 3.

DISCUSSION

A. Development of the Method

The method presented herein, of calculating the windbox assembly flow

distribution, is the result of what is obviously a greatly simplified treatment; numerous assumptions were made in the development of the method. The validity of each of these assumptions will now be examined.

Assumption (1): Constant total pressure at the compartment inlet plane.

Air issuing from a duct branches to each of the windbox assemblies; the fluid is moving at a low velocity relative to that at the nozzle exit. It would be reasonable to assume that the total pressure loss between the supply duct exit and the compartment inlet plane is a negligible fraction of the velocity head at the nozzle exit. It is all the more realistic to assume, as is the case herein, that the total pressure distribution in the supply duct and the consequent losses along individual streamlines, are such that the total pressure is uniform at the compartment inlet plane.

Assumption (2): Constant density fluid within the windbox assembly.

The reasoning for this assumption is analagous to that set forth in (1); note that while isothermal flow is not implied between the supply duct and the compartment inlet, it is assumed within the windbox assembly.

Assumption (3): Constant static pressure at the nozzle exit plane.

The static pressure of the jets issuing from the windbox nozzles is equal to the local furnace pressure. The variation in furnace pressure throughout this region should be negligibly small.

Assumption (4): Fully turbulent flow.

This is a valid assumption for the vast majority of cases; unit Reynolds numbers(based on nozzle exit velocity) greater than 10^5 per foot are typical even for small opening of compartment dampers.

Assumption (5): The compartment loss coefficient for existing configurations are adequately represented by the formulations presented herein (i.e. Figure 1 and Equation (6)).

Curves of K versus damper position, as calculated from Figure 1 and Equation (6), are shown in Figure 4 for compartment outlet/inlet area ratios (i.e. A(I)/B(I) of 0.534, 0.322 and 0.136; these values cover the range of our existing compartments. Results obtained from the cold-flow model tests of Reference 5, at area ratios of 0.322 and 0.136, are also shown in this figure; the

test results are seen to be in excellent agreement with the predicted values. These test results indicate that nozzle tilt, flow rate, firing angle, the presence of turning vanes and probably compartment inlet interaction, are secondary influences on compartment pressure loss and consequently on compartment flow rate. These results justify the omission of these factors in the development of the method presented herein.

B. Previous Calculations

In the previous method of calculating the windbox assembly flow distribution (Reference 1), the compartment loss coefficient was determined from the equation

$$K(I) = KO + K_D(I) * \left[\frac{A(I)}{B(I)}\right]^2$$

where $K_D(I)$ was specified as herein KO evaluated from test values of the total secondary air flow and windbox/furnace ΔP. Highly closed damper positions result in a very large value of K_D, as is seen in Figure 1, and a small error in this parameter will result in a large variation in KO. Program runs with all compartment dampers at or near the full open position yielded values of KO consistent with the value presented herein, i.e.,

@ 100% open, $K_D \approx 0.1$, $K = K/100\%$

from Equation (6), $K/100\% \approx 1 + 1.7 * \left[\frac{A}{B}\right]^2$

for existing geometries, $0 < \left[\frac{A}{B}\right]^2 < 0.29$

therefore, with $KO \approx K/100\%$, $1 < KO < 1.5$

Program runs with one or more compartment dampers highly closed would sometimes yield values of KO outside this range; in rare cases this would result in operational difficulties.

REFERENCES

1. N. D. Brown, "COMPAIR, Burner-Compartment Air-Flow Distribution Computer Program," Project No. 121029, September, 1971.

2. "Flow of Fluids Through Valves, Fittings, and Pipe," Crane Co., Technical Paper No. 409, May, 1942.

3. R. V. Giles, "Fluid Mechanics and Hydraulics," Schaum Publishing Co., 1962.

4. P. S. Dickey & H. L. Coplan, "A Study of Damper Characteristics," Trans. of the ASME, February, 1942.

5. N. D. Brown, "Windbox Compartment Flow Tests," Test Report 72-6, Project No. 412003, March 2, 1972.

DAMPER LOSS COEFFICIENT
VS.
POSITION

$$K_D = \frac{2(P_{T_1} - P_{T_2})/R}{(Q/A)^2}$$

P_{T_1} = Total Pressure @ "1"

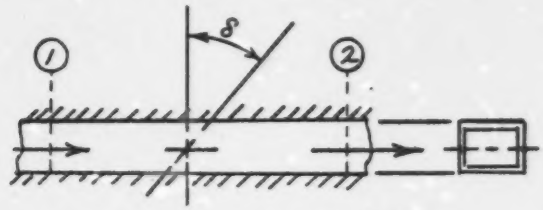
P_{T_2} = Total Pressure @ "2"

R = Fluid Density

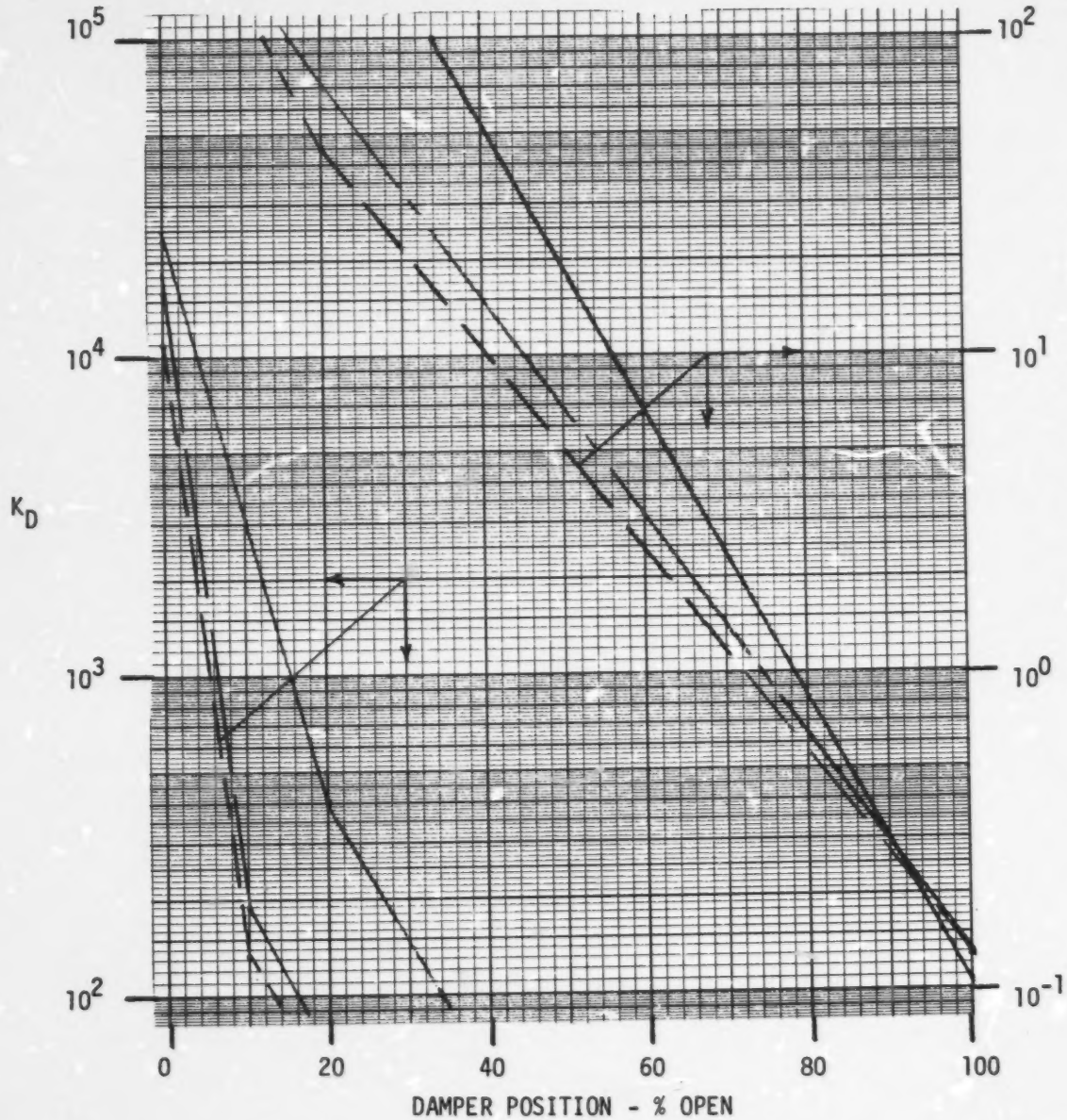
Q = Volume Rate of Flow

A = Flow Area

% Open = $(\delta/90) \times 100$



1 Blade
2 Blades
3 Blades



AIR FLOW DISTRIBUTION TO WINDBOX COMPARTMENTS
ALABAMA POWER AND LIGHT CO., BARRY #2
EPA '73 - '74 TESTS

FLOW DISTRIBUTION FOR TEST NO. 5

PER CENT EXCESS AIR 22.7

COMPART-MENT (NO.)	FIRING	AREA WT. FLOW (% OF TOTAL)	DAMPERS (% OPEN)	ACTUAL FLOW (% OF TOTAL)
1		9.44	60	7.8
2	Yes	6.55	20	8.39
3		18.03	100	16.37
4	Yes	6.55	20	8.39
5		9.44	100	8.64
6		9.44	100	8.64
7	Yes	6.55	20	8.39
8		18.03	100	16.37
9	Yes	6.55	20	8.39
10		9.44	100	3.64

Firing Fuel Compartment Total Air Flow (%) = 33.55
Air Flow Above Burner Zone (%) = 3.9
Air Flow to Burner Zone (% of Theor. Air) = 117.91

FLOW DISTRIBUTION FOR TEST NO. 20

PERCENT EXCESS AIR 24.2

COMPART-MENT (NO.)	FIRING	AREA WT. FLOW (% OF TOTAL)	DAMPERS (% OPEN)	ACTUAL FLOW (% OF TOTAL)
1		9.44	100	9.42
2		6.55	100	6.85
3		18.03	50	14.93
4	Yes	6.55	30	10.27
5		9.44	50	7.68
6		9.44	50	7.68
7	Yes	6.55	30	10.27
8		18.03	50	14.93
9	Yes	6.55	30	10.27
10		9.44	50	7.68

Firing Fuel Compartment Total Air Flow (%) = 30.82
Air Flow Above Burner Zone (%) = 23.73
Air Flow to Burner Zone (% of Theor. Air) = 94.72

COMPFLOW

Definition of Output

1. The "AREA WT. FLOW" is the ratio of the compartment free area to the total free area of the corner; as such it is a realistic approximation of the actual compartment (secondary) flow only when all compartment dampers are full open.

2. The comparment "ACTUAL FLOW" is the ratio of the compartment mass flow rate (including mill air if applicable) to the total mass flow to the corner (see ANALYSIS, equation (7)).

3. The "FIRING FUEL COMPARTMENT TOTAL AIR FLOW" is the ratio of the total mass flow rate to firing fuel compartments (including mill air if applicable) to the total mass flow to the corner.

4. The "AIR FLOW ABOVE BURNER ZONE" is defined as the percentage of the total mass flow rate supplied above the uppermost firing fuel compartment, less 50% of the flow to the compartment immediately above it.

5. % Theoretical Air = $\left(1 - \frac{\text{\% Air Above Burner Zone}}{100}\right)$(100 + % Excess Air) to Burner Zone.

COMPARTMENT LOSS COEFFICIENT
VS.
DAMPER POSITION

$$K = \frac{2(P_{T_x} - P_{s_y})/R}{(Q/A)^2}$$

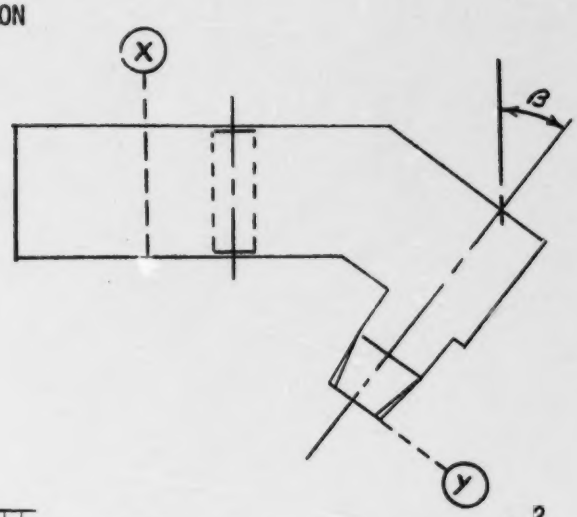
P_{T_x} = Total Pressure @ "x"

P_{s_y} = Static Pressure @ "y"

R = Fluid Density

Q = Volume Rate of Flow

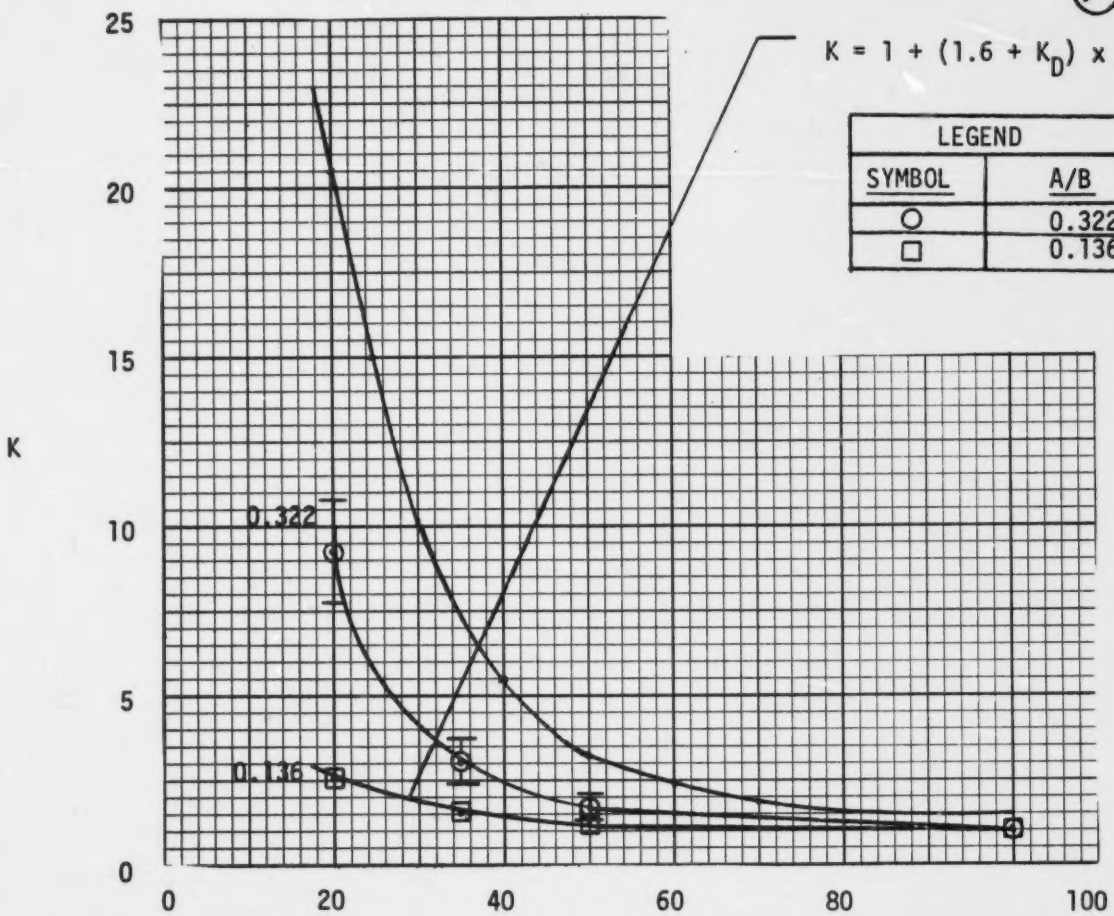
A = Nozzle Exit Area



$$\frac{A}{B} = 0.534 = \frac{\text{Nozzle Exit Area}}{\text{Compart. Inlet Area}}$$

$$K = 1 + (1.6 + K_D) \times \left(\frac{A}{B}\right)^2$$

LEGEND	
SYMBOL	A/B
○	0.322
□	0.136



DAMPER POSITION - % OPEN